FINDINGS OF FACT, CONCLUSIONS
OF LAW, AND ORDER

TABLE OF CONTENTS

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Don Storm	Chair
Tom Burton	Commissioner
Marshall Johnson	Commissioner
Cynthia A. Kitlinski	Commissioner
Dee Knaak	Commissioner

In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota

ISSUE DATE: September 29, 1993

DOCKET NO. E-002/GR-92-1185

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On November 2, 1992, Northern States Power Company's Electric Utility (NSP or the Company) filed a petition seeking a general rate increase of $119,000,000, or 9.0 percent, effective January 1, 1993.

On December 14, 1992, the Commission issued Orders accepting the Company's filing, suspending the proposed rates, and setting the matter for contested case hearing. The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Richard C. Luis to the case. The Office of Administrative Hearings also assigned Administrative Law Judge Allan W. Klein to the concurrent gas utility rate case, Docket No. G-002/GR-92-1186.

On December 18, 1992, ALJs Luis and Klein convened a joint electric and gas prehearing conference.

On December 29, 1992, the ALJs issued an Advance Notice of Key Decisions in Prehearing Order. In that Notice the ALJs determined the order of trial on the electric, gas and common issues. The ALJs also issued an Order Setting Deadline for Intervention.

On December 31, 1992, the Commission issued its ORDER ADOPTING INTERIM RATES in the electric case, authorizing an interim rate increase of $71,158,000, effective January 1, 1993.

On February 2, 1993, the ALJs issued a Prehearing Order establishing the hearing schedule and procedural guidelines. The Order determined that Judge Luis would hear electric issues and certain issues common to the gas and electric cases. Judge Klein would hear gas issues and certain other common gas and electric issues. The Prehearing Order also granted intervenor status in the electric case to the parties listed in the following section.

On February 17 and 19, 1993, NSP filed a Motion to Update and Supplemental Motion to Update its initial electric rate case filing. The net of the two Motions would reduce the NSP electric Minnesota jurisdictional test year revenue requirement by $1,415,000 annually to reflect certain changes which had occurred since the November, 1992 initial electric rate case filing. On March 25, 1993, Judge Luis granted the Company's Motions.

On February 22, 1993, the intervenors filed direct testimony regarding electric issues and issues common to the gas and electric cases. On March 23, 1993, NSP and certain intervenors filed rebuttal testimony. On April 2, 1993, NSP and certain parties filed surrebuttal testimony.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

The intervenors and their representatives in this matter are as follows:

Minnesota Department of Public Service (the Department), represented by Dennis D. Ahlers, Mark A.R. Chalfant, Brent Vanderlinden and Scott Wilensky, Special Assistant Attorneys General, Suite 200, 121 7th Place East, St. Paul, Minnesota 55101;

Residential Utilities Division of the Office of the Attorney General (RUD-OAG), represented by Eric F. Swanson and Gary R. Cunningham, Special Assistant Attorneys General, Suite 1200, NCL Tower, 445 Minnesota Street, St. Paul, Minnesota 55101-2130;

Minnesota Energy Consumers (MEC), represented by James J. Bertrand, 150 South 5th Street, Suite 2300, Minneapolis, Minnesota 55402;

Suburban Rate Authority (SRA), represented by Corrine A. Heine and James M. Strommen, 470 Pillsbury Center, Minneapolis, Minnesota 55402;

University of Minnesota (U of M), represented by Peter H. Grills and David E. Crawford, 800 Norwest Center, St. Paul, Minnesota 55101;

City of St. Paul, Municipal Pumpers Group and Board of Water Commissioners of St. Paul (St. Paul), represented by Thomas J. Weyandt, 800 Landmark Towers, 345 St. Peter Street, St. Paul, Minnesota 55102;

Champion International (Champion), represented by Catherine Dominguez and Lloyd Grooms, 3200 Minnesota World Trade Center, 30 East 7th Street, St. Paul, Minnesota 55101;

Minnegasco, represented by John C. Sprangers, 201 South 7th Street, Minneapolis, Minnesota 55402;

North Star Steel and Praxair, represented by Susan M. Swift and Robert Lee, 1600 TCF Tower, Minneapolis, Minnesota 55402;

Metalcasters of Minnesota (Metalcasters), represented by David Sasseville and William Flynn, 4200 IDS Center, Minneapolis, Minnesota 55402;

Metropolitan Senior Federation (Seniors), represented by Elmer W. Scott, Suite 190, 1185 University Avenue West, St. Paul, Minnesota 55104;

MAE, Inc., represented by Katy Wortel, 1411 Pohl Road, Mankato, Minnesota 56001;

Energy CENTS Coalition, represented by Pam Marshall, 4100 Vernon Avenue South, St. Louis Park, Minnesota 55416;

B. The Company

The Company was represented in the electric case and in matters common to the electric and the gas case by David A. Lawrence, Michael J. Hanson and Audrey A. Zibelman, 414 Nicollet Mall, Minneapolis, Minnesota 55401.

III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

The ALJs held joint public hearings to receive comments and questions from non-intervening ratepayers. At each hearing, persons were free to speak to both electric and gas issues. The dates and locations of the hearings are as follows:

March 10, 1993 Montevideo
March 11, 1993 Minneapolis
March 17, 1993 Dilworth
March 18, 1993 St. Cloud
March 24, 1993 St. Paul
March 25, 1993 Coon Rapids
March 30, 1993 Winona
March 31, 1993 Mankato

In all, 48 ratepayers spoke at the combined public hearings. Of this number, 13 favored the proposed increases, 27 opposed them, and eight were either neutral or expressed both sentiments. Only a few speakers addressed the gas issues; most addressed the proposed increase in electric rates.

Persons who favored the proposed rate increases spoke from two perspectives: as shareholders; and as representatives of non-profit organizations. The latter group cautioned against NSP's becoming so "lean and mean" that employees were unable to contribute to charitable or community organizations through either donations or volunteer efforts.

In St. Cloud, a petition was introduced into the record bearing signatures of 780 NSP customers who were opposed to any rate increase for either electric or gas service.

A number of individuals stated that at some point they had been forced by financial circumstances to choose between paying utility bills or paying their rent or mortgage. Some of these speakers favored a low income discount.

Most written comments were directed to the electric rather than to the gas issues. A number of persons compared the size of the proposed increases with recent cost-of-living increases in social security and other similar government programs.

Approximately 130 written comments were received in favor of the Energy CENTS/RUD-OAG proposal for a discount rate for low income persons. An additional 81 persons signed petitions circulated by Energy CENTS in support of the discount rate campaign. The next largest group of comments totalled 119 persons who expressed opposition to the proposed rate increases.

IV. EVIDENTIARY HEARINGS

Administrative Law Judge Luis held evidentiary hearings in the electric and common proceedings. The hearings commenced April 7, 1993, and concluded on April 26, 1993. Administrative Law Judge Klein heard certain common issues on April 27-29, 1993.

V. PROCEEDINGS BEFORE THE COMMISSION

On April 13, 1993, NSP, the Department, Minnegasco, and the U of M executed an Agreement and Stipulation regarding a Standby Rider for standby electric service. No party opposed the stipulation.

On April 13 and 14, 1993, NSP, Metalcasters, North Star Steel, Praxair, Inc., MEC, Champion, the Municipal Pumpers Group and the Board of Water Commissioners of the City of St. Paul entered into a Stipulation Agreement on Rate Design for Commercial and Industrial (C & I) Interruptible Classes. The Department filed comments in opposition to a portion of this Stipulation. Parties were thereafter allowed to brief the issues in light of the opposition expressed by the Department.

On June 7, 1993, Judge Luis filed an Order Recommending Acceptance of Stipulation Agreement to the Public Utilities

Commission. In that Order Judge Luis found that the parties' two filed Stipulations were supported by substantial evidence and that acceptance of the Stipulations would result in just and reasonable rates. The ALJ submitted the stipulations to the Commission for approval, modification or rejection under Minn. Stat. § 216B.16, subd. 1(a).

Administrative Law Judge Luis filed a report on July 16, 1993, in which he addressed the Revenue Requirements section of the electric proceedings. Judge Luis filed a second report on July 23, 1993, in which he addressed Rate Design issues in the electric rate case.

On August 4 and 6, 1993, the Commission heard oral argument on the issues common to the gas and electric utilities. On August 20, 1993, the Commission heard oral argument regarding the electric issues.

Upon review of the entire record of this proceeding, the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

VI. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and 216B.02 (1992). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1992).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1992) and Minn. Rules, part 1400.0200 et seq.

VII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7830.4100, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of the Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all the parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1992), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd. 4 (1992).

VIII. THE COMPANY

NSP's electric utility serves approximately 1,019,226 customers in the state of Minnesota.

NSP's major wholly owned subsidiaries include the NRG Group, Inc., which is involved in a variety of non-regulated energy enterprises.

IX. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1992) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Rates for Electric Service in Minnesota, 416 N.W. 2d 719 (Minn. 1987). In the Northern States Power case the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

X. TEST YEAR

The Company proposed the twelve-month period from January 1, 1993 through December 31, 1993 as its test year in this proceeding. The test year data was fully projected, based on the Company's budgeting process. The ALJ found that the Company's fully forecasted test year was consistent with the Company's last filing and was reliable for ratemaking purposes.

The Commission agrees with the ALJ that the Company's proposed test year is appropriate. The Commission accepts the Company's proposed test year for purposes of this general rate case.

XI. RATE BASE

In its initial filing, NSP proposed a rate base of $2,392,040,000. After two updates, rebuttal testimony, and a depreciation update, the Company proposed a rate base of $2,376,552,000 in its reply brief.

In order to delineate the changes from the initial filing to the Commission's finally determined rate base, the Commission will use the initially filed amount as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues will be discussed below.

A. Incentive Compensation

As discussed in the Operating Income Statement section of this Order, the Commission disallowed recovery of incentive compensation. NSP does not capitalize incentive compensation but does capitalize a portion of the pension related to the incentive compensation. The amount of pension capitalized in the Minnesota jurisdiction electric utility is $188,000. The Commission will disallow $94,000 from rate base, the average of the beginning and ending balances.

B. Employee Loans

As a benefit to its employees, the Company makes loans to employees to purchase personal computers (PCs). The loans are for 36 months at zero interest.

The question at issue is whether the balance of employee loans should be included in rate base.

The Company argued that while there may not be a direct relationship between these loans and the provision of utility service, there exists an indirect benefit to customers. Approximately 50 percent of NSP's employees utilize PCs in some way as part of their job. NSP claimed it seems reasonable to assume that employee's computer knowledge and job skills are enhanced by the use of PCs at home.

The Department recommended that ratepayers not be responsible for this employee benefit, because it does not contribute to the provision of utility service. The Department argued that if a return on the loan balance is required, the return should either be provided by the employees who receive the loans or continue to be absorbed by the shareholders.

The ALJ rejected the inclusion of employee loans in rate base finding that the relationship between these loans and the provision of utility service is too remote to justify requiring ratepayers to pay a return on these loans.

The Commission agrees that the Company has not demonstrated that employees' home use of computers benefits the ratepayers. The Company did not document what portion of the employees who purchased computers use a PC as part of their job. The Commission believes that the appropriate method for the Company to provide computer training for employees is through NSP's training program where the training would be specifically related to the job.

The Commission concludes that employee loans should not be included in rate base, resulting in a reduction to rate base of $1,067,000.

C. CWIP

Historically, there has been substantial controversy over the treatment of construction work in progress (CWIP) for rate purposes. Minnesota tends to allow CWIP in rate base with the allowance for funds used during construction (AFUDC) offset to the income statement.

Minn. Stat. §216B, subd. 6a provides:

> Construction work in progress. To the extent that construction work in progress is included in the rate base, the commission shall determine in its discretion whether and to what extent the income used in determining the actual return on the public utility property shall include an allowance for funds used during construction, considering the following factors:

(a) the magnitude of the construction work in progress as a percentage of the net investment rate base;

(b) the impact on cash flow and the utility's capital costs;

(c) the effect on consumer rates;

(d) whether it confers a present benefit upon an identifiable class or classes of customers; and

(e) whether it is of a short-term nature or will be imminently useful in the provision of utility service.

In the original filing, NSP included $8,916,000 of AFUDC as test year income. The related CWIP included in rate base is $143,380,000. NSP calculates AFUDC monthly on the CWIP balance excluding short-term projects, non-construction projects, and completed projects not reclassified to plant.

The SRA argued that the length of time required to construct the plant is not the relevant factor. The SRA recommended that AFUDC be calculated on short-term CWIP and that the CWIP balance be based on the beginning of year/end of year average rather than the monthly balances. This would increase the amount of AFUDC included as income for the test year by $2,196,000.

As a result of information request responses from NSP, the SRA concluded that its original recommendation needed to be revised. The SRA indicated that it lacked the time and resources to pursue its original position, and withdrew the original position at hearing.

NSP argued that its practices have been consistent since its first rate case in 1975. It further argued that the Commission addressed NSP's CWIP and AFUDC accounting and budgeting procedures in Docket Nos. E-002/GR-81-342 and E-002/GR-85-558 and concluded that NSP's treatment was consistent with past Commission treatment.

The Company argued that due to the construction fluctuations throughout the year, it is more appropriate to calculate AFUDC based on monthly balances as done by NSP. The NSP method is more accurate than the beginning of year/end of year method recommended by the SRA. In addition, the SRA failed to reduce CWIP for non-construction expenditures and CWIP amounts which should be reclassified as "in service." After making these adjustments, the impact of the SRA recommendations on NSP's jurisdictional revenue requirement is minimal and would not justify a policy change.

In its brief, the SRA recommended that the Commission adopt rate filing rules requiring detailed information on CWIP and AFUDC. The SRA argued that this information would allow parties and the

Commission to be in a position to evaluate the impacts of the Company's proposed ratemaking treatment of CWIP and AFUDC.

In reply, NSP argued that it provided the necessary information to the SRA in response to information requests. Detailed balances for each CWIP item were provided in the original filing. Rate case filing requirements should not be modified because one party could not devote the resources to understand the procedures.

The ALJ recommended no adjustment. The ALJ declined to recommend adopting a rule as recommended by the SRA, stating that the SRA proposal was too late to receive detailed scrutiny.

The Commission concludes that the calculation of AFUDC made by the Company is consistent with past Commission treatment of this issue and the result is reasonable to use in setting rates in this case.

D. Depreciation Study

NSP included depreciation expense based on the depreciation rates approved by the Commission at the time of the original filing. However, the Company also had its five-year depreciation study in Docket E,G-002/D-92-869 and its annual study in Docket G,E-002/D-92-1066 pending before the Commission. The Company proposed that the rate filing be adjusted to reflect the decisions in the pending dockets, if available before the close of the record in this rate proceeding. Orders were issued on April 23, 1993 and April 15, 1993, respectively. Incorporating these decisions reduces rate base by $1,110,000.

In addition, the Company proposed that the Commission's decision regarding a change in depreciation method for the interim storage facility at Prairie Island, pending before the Commission in Docket E-002/D-92-1411, be incorporated into the final decision in this rate proceeding. The Commission issued its order on March 12, 1993. Incorporating this decision increases rate base by $1,118,000.

The Department and the ALJ recommended that these adjustments to the original filing are appropriate. The Commission will incorporate the above decisions into the test year. This will provide for the most current information to be reflected in the rate case, leading to a more accurate test year depreciation expense.

E. Wind Turbine Project

NSP originally expected to install 5 MW of wind generation by late 1993 and 20 MW in 1994. NSP also expected that it would own and operate the facilities. In its February 17, 1993 update, NSP indicated that the 5 MW originally proposed for 1993 would not be operational in 1993 and would remain in construction work in progress (CWIP). In rebuttal testimony, NSP indicated that it no longer intended to own and operate the first phase of the wind project. As a result, NSP proposed excluding the wind projects from the test year.

No party disputed the adjustments. The ALJ found the adjustments appropriate.

The Commission will exclude the wind projects, reducing rate base by $7,360,000.

F. Prairie Island Back-Up Generators

NSP included approximately $109 million ($126 million total company) in test year rate base for its recent expenditures related to the station blackout/electrical safeguards upgrade at the Prairie Island nuclear generating facility. The upgrades were made necessary by Nuclear Regulatory Commission (NRC) rules related to station blackout. Prior to the upgrade, two diesel generators backed up safety and cooling systems. With the upgrades, four generators now back up the safety and cooling systems. Additional modifications were made to reduce the dependency on the substation for the emergency connection between the two nuclear units at Prairie Island.

NSP agreed to perform a nuclear cost estimation study as recommended by the Department, with slight modifications.

The Department investigated the costs and recommended no financial adjustment. The Department also compared the costs of NSP's project with similar projects at other nuclear facilities and recommended NSP's costs as prudent.

The Department did raise concern about NSP's nuclear cost estimation process. The final costs of complying with the NRC rule exceeded the 1988 estimates of compliance costs by 106 percent.

The ALJ recommended the project costs as prudent and appropriate for recovery. The ALJ also recommended a study of the nuclear cost estimation process.

The Commission accepts the ALJ's recommendation to include the costs for recovery in the test year. No adjustment to the originally filed data is necessary.

The Commission also will direct NSP to conduct a study of its nuclear cost estimation process as recommended by the Department and the ALJ. The Commission will direct that the study be completed within 120 days of the date of this Order and include:

1. a compilation and comparison of the original estimated and final costs for capital improvement projects with budgets greater than $250,000 at the Company's nuclear facilities since 1988;

2. any Company-sponsored recommendations for changes to the cost estimation process for evaluating and implementing capital improvements; and

3. an evaluation and discussion of potential administrative improvements that would ensure the performance of a complete cost/benefit analysis for each engineering option before the corporate-level review is performed.

G. Rate Case Expense

As discussed in the Income Statement section of this order, part E, the Commission will allow the Company to deduct the full amount of test year rate case expenses from the refund of excess interim rates. This results in no rate base adjustment.

However, should there not be sufficient refund, the Commission will permit the inclusion of the $217,000 unamortized balance of rate case expense in rate base, as discussed in part E of the Income Statement section of this order.

H. Refuse Derived Fuel

1. Introduction

In the Waste Management Act of 1980, the Minnesota legislature mandated counties in the Minneapolis/St. Paul metropolitan area to move from landfilling to other methods of disposal for municipal solid wastes (MSW). NSP subsequently entered into the business of processing MSW into fuel at two facilities located at Newport and Elk River. NSP's unregulated affiliate, NRG-RR, holds the major interest in these two facilities.

NRG-RR currently has agreements with a number of MSW sources, including Anoka, Hennepin, Ramsey and Washington Counties, under which it converts MSW into refuse derived fuel (RDF). This RDF is burned at the Company's regulated generating plants known as Red Wing and Wilmarth. NRG-RR also sells RDF to United Power Association (UPA), which in turn sells power back to NSP.

2. Previous Proceedings Before the Commission

In 1984, NSP was considering the prospects of entering into the MSW processing business and of converting generating plants into burning RDF. NSP petitioned the Commission for an advisory opinion on future rate case treatment of expenses associated with the processing facilities and the generating plants. On August 15, 1985, the Commission issued an Advisory Opinion addressing the Company's questions. The Commission expressed doubt that RDF processing facilities should be included in rate base. The costs of conversion to burning RDF and of generating electricity in RDF-fueled plants could be considered "reasonably necessary to the efficient and reliable provision of utility service" and thus be recovered in rates if certain conditions were met. The Commission stated that the following minimal conditions must be present:

1. that RDF be an economically priced fuel that provides electric generation at a cost competitive with other fuels;

2. that NSP is able to secure long-term contracts for the purchase of RDF; and

3. that the burning of RDF in no way shortens plant life.[1]

In NSP's 1986 rate case, Docket No. E-002/GR-85-558, the Company included in its test year construction work in progress (CWIP) the costs of modifying the Wilmarth and Red Wing plants to burn RDF. The Commission found that "RDF-related CWIP meets the Commission's traditional test of prudency and substantial certainty for inclusion in CWIP." The Commission deferred consideration of intervenors' arguments that the allowable annual revenue requirement for RDF generation should be limited to Public Utility Regulatory Policies Act (PURPA) qualified facility (QF) payments.

In NSP's 1991 rate case, Docket No. E-002/GR-91-1, the Commission allowed recovery of NSP's costs of conversion to RDF plants, test year operating costs for RDF-fueled plants, and the cost of power purchased from the UPA RDF-fired plant. The Commission rejected the arguments raised by MAE's predecessor, Mankato Citizens Concerned with Preserving Environmental Quality (MCCPEQ). MCCPEQ had argued that the costs of conversion were too high compared with the Company's original estimates, costs of generation were high compared to other NSP plants, and that ratepayers were subsidizing NSP's power purchases from UPA.

In the 1991 rate case Order, dated November 27, 1991, the Commission adopted the ALJ's recommendation that a separate investigation into NSP's RDF operations be commenced.

On December 12, 1991, the Commission issued its ORDER INITIATING INVESTIGATION in Docket No. E-002/CI-91-966. In that Order the Commission asked the Department to investigate NSP's RDF activity. The Department's report was to address Mankato's assertions that ratepayers have subsidized non-regulated RDF operations, that RDF plant and purchased power costs are unreasonable, and that NSP has failed to comply with the conditions of the Advisory Opinion. The Commission stated that the results of the investigation should be available for incorporation into the Company's next rate case.

---

[1] No party in this rate case has made any allegation that the burning of RDF shortens plant life.

The Commission later ordered Mankato, the Department and NSP to meet to discuss contested issues regarding NSP's RDF activity and to report to the Commission on the discussions. On October 10, 1992, the Commission issued its ORDER ACCEPTING REPORT AND CONSOLIDATING RECORD. In that Order the Commission accepted the Department's report dated May 1, 1992 and consolidated the investigation, along with the parties' reply comments, into the Company's next general rate case.

3. Positions of the Parties; the ALJ

a. The Department

The Department made three observations regarding the RDF issue: the Commission has never determined the prudence and reasonableness of the Company's RDF investment; the Commission must decide if ratepayers have been subsidizing the Company's nonregulated RDF operations; the Commission has never set a method for determining if NSP meets the 1985 Advisory Opinion criteria.

According to the Department, the inherent potential for self-dealing in the NSP RDF operations, plus the Commission's requirement of competitiveness in the Advisory Opinion, create the need for a standard of "ratepayer indifference." Under this standard, NSP's costs of RDF operations must not exceed comparable costs of generation with other fuels. The Department argued that ratepayer indifference requires that NSP's costs be capped at those of NSP's coal-fired Sherco 3 generating facility.

The Department recommended that NSP's costs be broken into capital investment, operating and maintenance (O & M) and fuel for purposes of capping. For capital, the Department used Sherco 3 avoided capacity cost, with adjustments for expected life after conversion and a 50 percent capacity factor for Red Wing and Wilmarth. For O & M, the Department recommended capping at Sherco 3's most recent six-year average. The Department compared NSP's RDF fuel costs with Sherco's coal, and did not use a system-wide average for fuel costs. The Department did not recommend a cap on NSP's fuel costs, because the Company's recent contract with NRG-RR showed cost improvement. The Department recommended future review of fuel costs if any changes in fuel contracts occurred.

The Department argued that NSP's claimed ratepayer benefits were unquantifiable, speculative and overstated. They also were not applied equally to QFs for purposes of comparison.

The Department recommended disallowance of the Company's test year capacity payments to UPA. The Department argued that there were cheaper alternatives available at the time the Company entered into the purchase power contract. The Department also stated that the Company must prove that a QF probably would have sold power to NSP, had the Company not contracted with UPA. Absent such proof, the payments should be disallowed.

b. MAE

MAE's main contention was that NSP's RDF facilities should be held to PURPA QF standards, and that ratepayers should pay only PURPA QF rates for power. MAE agreed with the Department that the standard prudence analysis was not sufficient in these circumstances, in which NSP is not at arm's length with its RDF supplier. Without capping at the QF rate, other potential QFs would be discouraged from entering into operation, and NSP ratepayers would be disadvantaged.

MAE stated that its capping formula, which differed from the Department's, was "not yet entirely in the record." MAE suggested a possible rate comparison with the Hennepin Energy Resource Corporation (HERC), a refuse-burning QF.

MAE declared that NSP had acted imprudently by underestimating its O & M costs in its original analysis. NSP was also imprudent because it failed to foresee further costs for environmental requirements such as the scrubber and baghouse added to its RDF facilities.

MAE argued that the facts called for the removal of the Red Wing and Wilmarth plants from rate base. In the alternative, the plants could remain in rate base, with the appropriate PURPA QF rate applied as a cap.

c. NSP

NSP argued that the Commission must apply the standard prudence review to the RDF facilities. Under this review, NSP acted prudently in its investment and management decisions. The Company should therefore be allowed recovery of its costs and a reasonable return on investment.

According to NSP, the Advisory Opinion refers only to the competitiveness of RDF as fuel; it does not state that RDF generation costs must be competitive with Sherco generation costs. There is no wording in the Advisory Opinion which justifies a rate cap on NSP's RDF operations.

NSP argued that capping would act as a disincentive for new technologies by disallowing prudently incurred expenses. Capping at Sherco 3 O & M costs ignores Sherco's economies of scope and scale. NSP's capital investment should not be adjusted for capacity because the RDF plants are fully dispatchable and will in the future operate at 70 percent capacity for significant periods.

NSP stated that the Commission recognized RDF's net benefits to ratepayers in the 1991 rate case Order; these benefits have increased since then. NSP cited a new contract with NRG-RR which includes incentives, and also reduced operating costs.

NSP opposed disallowance of its capacity payments to UPA. NSP stated that the current contract price is lower than NSP's avoided costs. The Company argued that it is impossible to prove at this time whether or not another QF would have sold power to NSP, had the Company not contracted with UPA. The Department's recommended disallowance should therefore not be implemented.

d. ALJ

The ALJ stated that a general prudence analysis, rather than an avoided cost comparison, should be applied to determine rate base or income treatment of the RDF operations. NSP has established a total cost/benefit to ratepayers from the "entire cost picture" of its RDF operations; it is therefore not appropriate to break costs into capital, O & M and fuel and place cost caps on these elements.

The ALJ found that the used and useful analysis in the Advisory Opinion was meant to apply to all costs associated with the Company's RDF operations, including capital costs, O & M costs, and fuel costs. The ALJ compared total O & M costs over the entire life of the RDF plants with Sherco 3 and found the comparison favorable to NSP. The ALJ found that an adjustment to capital costs for plant life was appropriate, but not an adjustment for capacity. The ALJ recommended that no cap be placed on RDF fuel costs, because future benefits of the new RDF supply agreement, including incentives, will outweigh past higher fuel costs. The ALJ recommended Commission review of ratepayer indifference under the Commission's authority over affiliated interest transactions, if future RDF purchase agreement modifications occur.

The ALJ found that MAE's HERC avoided cost cap concept was not in the record and should therefore not be credited. The ALJ disagreed with the MAE that an adjustment should be made for the uncertainty of future RDF supplies. The ALJ found that MAE had not proven that NSP acted imprudently in its RDF operations.

The ALJ concluded that NSP should be allowed to recover the costs of its RDF operation and to earn a reasonable return on its investment.

4. Commission Analysis

a. The Prudence Standard; Analysis Under the Standard

A fundamental concept of the regulatory ratemaking process allows utilities which prove that their costs and investments are prudent and reasonably incurred to recover their costs in rates, plus a reasonable return on investment. This prudence standard of review is firmly grounded in statutory and case law, has been found to be an effective tool in ratemaking, and has been traditionally relied upon by all parties to the regulatory ratemaking process. The Commission finds that no compelling reason has been offered to abandon the prudence standard in this case. The Department's extraction of a new avoided cost standard from the 1985 Advisory Opinion is too strained to persuade the Commission. There is nothing in the wording or context of the Advisory Opinion which can reasonably be interpreted as a directive to abandon the prudence standard of review. Neither does the fact that NSP and NRG-RR are affiliates cause the Commission to abandon its traditional approach to ratemaking. The relationship between NSP and NRG-RR is a factor which may well justify very close review of their transactions, perhaps with continued additional monitoring and oversight. The affiliate relationship of itself, without proof of wrongdoing, does not warrant abandonment of the traditional prudence standard of review for ratemaking purposes.

The Commission therefore agrees with the ALJ that a prudence analysis should be applied to NSP's "entire cost picture" to determine if the Company's RDF operating and investment costs should be recovered from ratepayers. This analysis takes into account the developmental, life cycle nature of utility ratemaking.[2] At the same time, it must be grounded in the test year record, to ensure that the utility made prudent and reasonable decisions in its investment and operational strategies in the test year. Upon such review, the Commission agrees with the ALJ that NSP's test year RDF investment and operating costs were prudent and reasonable and should be allowed.

The Commission disagrees with MAE that adjustments must be made for NSP's original cost estimates. NSP's venture into a new technology meant that some projections and estimates would be proved wrong. MAE, however, has not proven that these miscalculations were evidence of imprudence or of wrongdoing. As the Commission stated in its November 27, 1991 rate case Order,

> RDF has advanced from the theoretical to the real. Projections and proposals have undergone changes required for actual implementation; contracts which then covered future actions are now being carried out. While the Commission established original conditions, management at NSP's regulated and unregulated operations have made many implementation decisions, including plant modifications and contract terms.

The Commission finds that differentiations between projected and actual costs do not demonstrate that NSP has acted imprudently.

---

[2] This characteristic is in contrast to QF avoided cost recovery, which is set at a stable rate throughout the life of the facility. Under the avoided cost concept, when investment and operational costs go down, it is expected that the QF will receive a higher profit. In contrast, the recovery of a regulated utility will remain tied to the utility's cost of service. This fundamental difference is one reason that rate recovery comparisons between QFs and utilities are problematical.

Further examining NSP's entire RDF costs under the prudence analysis, the Commission finds that there is record evidence that the Company's RDF operations are increasing in efficiency. The new technology has been fully developed, and required environmental investments have been made. Viewed on a life cycle basis, the RDF operations are moving to a higher level of efficiency, and greater comparability with NSP's traditional generation facilities. The Commission also finds that a fair comparison with Sherco 3 must include the economies of scale inherent in the much larger Sherco operation. Viewing the RDF operations on a developmental basis, and bearing in mind the differences between the RDF operations and larger traditional generation facilities such as Sherco, the Commission finds that the Company's RDF costs were prudently incurred.

Viewing the entire cost picture of the Company's RDF costs requires a look at the cost of the fuel source firing the Red Wing and Wilmarth plants. Recent contractual agreements between NSP and NRG-RR, including incentive payments, guarantee a source of fuel which should grow increasingly favorable in comparison to traditional fuels. The Commission finds that this element of the entire cost picture is further evidence of the prudence of the Company's investment.

b. The Commission's Past Treatment of NSP's RDF Operations

The Commission's past treatment of NSP's RDF operations is a further reason for allowing recovery of NSP's RDF costs. In 1984, the Company sought Commission advice before entering fully into the RDF technology. In its 1985 Advisory Opinion, the Commission stated that rate base treatment of the RDF processing facility was "doubtful." The Commission indicated that, under certain circumstances, recovery of investment and expenses associated with RDF generation would be possible.

NSP proceeded to divide its RDF operations into the regulated generation facilities and unregulated processing facilities. In 1986, the Commission allowed the Company CWIP recovery of its investments in RDF plant modifications. In 1991, the Company sought and received rate base and income recovery of its RDF generation costs. Although the Commission ordered an investigation of the Company's RDF facilities, the Commission did not make any finding of imprudence or cross-subsidization in the 1991 rate case. In both the 1991 Final Order and the Order After Reconsideration, the Commission viewed the developing RDF technology in the long view, and found sufficient overall benefits to ratepayers to justify recovery.

The Commission finds that there has not been evidence submitted in this rate case which would justify a departure from the Commission's previous treatment of NSP's RDF operations. Indeed, there has been evidence presented of increased O & M efficiencies, the completion of environmental modifications, and more favorable fuel contracts, all of which would indicate increased net benefits for ratepayers. Past Commission advisory and ratemaking treatment of NSP's RDF operations suggest that rate recovery of NSP's costs is justified in this rate case.

c. Intervenor Arguments

The Department argued that many of NSP's claimed RDF benefits to ratepayers were unquantifiable and speculative, and thus should not enter into the prudence analysis. The Commission disagrees. As the Commission stated at p. 4 of its 1985 Advisory Opinion,

> The Commission supports NSP's efforts to use a renewable resource while addressing the environmental problem of waste landfill. The Commission recognizes that there are potential benefits derived by the general public from the use of RDF as a boiler fuel. For example, the use of RDF as an alternative to fossil fuel decreases the State's reliance on nonrenewable fossil fuel. Additionally, the burning of RDF in place of coal may reduce sulfur emissions.

The Commission continues to believe that these benefits, while not precisely quantifiable, are real, and that they apply to NSP ratepayers along with the general public. The Commission has the discretion to look at the overall picture formed by the Company's RDF operations when performing its prudence analysis.

The Department and MAE argued that the affiliate relationship between NSP and NRG-RR requires a departure from the normal prudence review and a capping of the Company's revenues at the avoided cost level. The Commission finds that any concerns or questions regarding the Company's relationship with NRG-RR must be met through a close review of the inter-affiliate transactions. This, rather than a departure from normal cost of service ratemaking, is the proper approach to the relationship between the regulated and unregulated operations. The Commission agrees with the ALJ that if concerns arise in the future from a change in the contract between NSP and NRG-RR, the Commission can and should explore the concerns through its authority under the affiliated interest statutes.

MAE argued that NSP had failed to prove that the life of its RDF units would extend beyond the duration of NRG-RR's contract for processing the Counties' MSW. The Commission finds that MAE has not shown that MSW will be unavailable when the current contracts expire. The Commission finds further that the Company's contractual commitments are sufficiently long-term to fulfill the requirements of the 1985 Advisory Opinion.

d. Capacity Payments to UPA

NSP seeks to recover costs associated with its purchase power agreement with UPA for 22 MW of RDF-generated capacity. The RDF which UPA burns is obtained from the Elk River processing plant, which is 85 percent owned by NRG-RR and 15 percent owned by UPA.

The Department argued that the test year UPA capacity payments should be disallowed, because NSP had not needed the capacity at the time it entered into the agreements.

The Commission notes that no party disputes NSP's present need of the UPA capacity. NSP has also submitted record evidence which shows that the test year UPA contract cost is below NSP's current avoided cost.

Applying a prudence analysis to the entire cost picture of NSP's UPA capacity purchases, the Commission finds that NSP acted prudently when it entered into its purchase power contract with UPA. The Commission also finds that the contract continues to bring a net benefit to ratepayers. The Commission will not disallow any portion of the UPA test year capacity costs.

e. Conclusion

The Commission finds that NSP's RDF operations fulfill the three standards set in the Commission's Advisory Opinion:

1. RDF is an economically priced fuel that provides electric generation at a cost competitive with other fuels;

2. NSP is able to secure long-term contracts for the purchase of RDF;

3. The burning of RDF in no way shortens plant life.

The RDF costs withstand the Commission's prudence analysis and the facilities are used and useful in the provision of electric service. The Company will be allowed rate recovery of its RDF operating and investment costs.

I. Cash Working Capital

NSP included negative cash working capital of $77,153,000 in its original filing. The cash working capital was calculated using a lead lag study.

Consistent with calculations supplied by the RUD-OAG, recommendations by the Department, and the ALJ, the Commission will adjust the filed test year cash working capital to reflect the effects of the Commission's income statement adjustments on cash working capital. Also, consistent with prior Commission decisions, the Commission will also adjust cash working capital to reflect the effects of the rate increase granted in this proceeding and for the effects of interest synchronization on the Commission's rate base. These adjustments result in an additional negative cash working capital of $1,147,000. The Commission concludes that the appropriate test year cash working capital is a negative $78,300,000.

J. Updates to Original Filing

NSP filed two updates to its original filing. The first was filed on February 17, 1993. The second was filed on February 19, 1993. Each will be discussed below.

1. February 17, 1993 Update

NSP included corrections and adjustments to its original filing due to changed circumstances in this update. The uncontested rate base adjustments accepted by the Commission are discussed below. Rate base adjustments included in the update for related cash working capital effects, rate case expenses, and the wind turbine project will not be discussed here. These items are subject to additional modifications and will be addressed on an individual basis elsewhere in this order.

a. Tax Benefit Transfers (TBT)

The Company discovered that it did not include the beginning of test year balance of tax benefit transfers (TBT) when it calculated the average balance for the test year. Correcting for this error reduces rate base by $2,659,000.

No party opposed this adjustment. The ALJ incorporated this adjustment without comment. The Commission accepts this adjustment as an appropriate correction of an error.

b. Prepayments

The Company discovered that it allocated coal option prepayments using a plant allocator instead of the energy allocator. Correcting for this error reduces rate base by $1,000.

No party opposed this adjustment. The ALJ incorporated this adjustment without comment. The Commission accepts this adjustment as an appropriate correction of an error.

c. United Hospital

The Company discovered that it neglected to reflect the contribution in aid of construction that will be received from United Hospital for the dispersed generation project, thereby overstating rate base. Correcting for this error reduces rate base by $337,000.

No party opposed this adjustment. The ALJ incorporated this adjustment without comment. The Commission accepts this adjustment as an appropriate correction of an error.

d. Fuel Handling and Inventory

Shortly after filing this rate case, the Company completed a study on fuel inventory. Based on the study, the Company decided to reduce its coal inventory to a 30-day supply. Incorporating this adjustment reduces rate base by $2,864,000.

No party opposed this adjustment. The ALJ incorporated this adjustment without comment. The Commission accepts this adjustment which leads to a more accurate reflection of test year fuel inventory.

2. February 19, 1993 Update

In the February 19, 1993 update, NSP proposed adjustments to its originally filed rate of return. Adjustments decreasing debt costs and modifying the capital structure were included.

As a result of the modifications to its proposed rate of return, the Company included adjustments to the rate base for changes in allowances for funds used during construction (AFUDC), nuclear decommissioning, and various related changes in cash working capital.

No party opposed the adjustments. The ALJ incorporated the adjustments without comment.

The Commission will incorporate the effects of the modifications to the rate of return on rate base for nuclear decommissioning expense and AFUDC, items which vary with the rate of return. However, the Commission will calculate the changes necessary to the original filing based on its finally determined rate of return. The Commission will detail adjustments to AFUDC and nuclear decommissioning below. Any adjustments for conservation expense and cash working capital will be included in the respective sections elsewhere in this order.

a. AFUDC

The Commission modified various components of NSP's requested overall rate of return, as discussed in the Rate of Return section of this order. The cost of short-term debt is a factor in calculating the test year allowance for funds used during construction (AFUDC). Incorporating the Commission's determination to decrease test year short-term debt costs to 4.0 percent into the AFUDC calculation reduces test year rate base by $879,000 from the originally filed amount.

b. Nuclear Decommissioning

The Commission will adjust test year decommissioning expense to reflect the rate of return finally authorized in this proceeding. Nuclear decommissioning funds held internally by NSP are paid a return based on the currently authorized rate of return. NSP filed its original decommissioning expense calculated based on its proposed rate of return of 10.10 percent. The Commission will adjust the test year cost to reflect the 9.08 percent rate of return awarded in this case. This adjustment will ensure that the internal fund earns a return based on the rate of return authorized for NSP. Without this adjustment, NSP would be paying the internal fund a return greater than its own authorized rate of return. NSP proposed this adjustment in its initial filing and no party opposed the concept of this adjustment. This adjustment reduces rate base by $541,000.

K. Budgeting

The Department reviewed NSP's budgeting practices and recommended the levels of capital expenditures as reasonable. The ALJ recommended the budgeted data as reasonable, accurate, and appropriate for the determination of just and reasonable rates.

The Commission accepts NSP's budgeted data as reasonable for purposes of setting rates in this proceeding.

L. Future Filing Requirements

In NSP's most recent electric rate case, Docket E-002/GR-91-1, the Commission ordered the Company to include the following items as filing requirements in future rate cases:

* comparisons of departmental budgets to DRI guidelines;
* budget documentation, volumes 5, 6, and 7;
* translation reports linking cost element, cost activity, and project budgeting mechanisms on a common and consistent basis to assure audit trail;
* month-by-month and year-end summary reports of contingency fund transactions and project substitutions;
* bridge schedules showing adjustments from unadjusted budget to rate case numbers; and
* summaries by FERC accounts.

NSP indicated that it would continue to provide the bridge schedules and the summaries by FERC accounts as part of the normal filing requirements. However, NSP did request that it be relieved of the requirement that the remaining four items be included as part of the official filing requirements which must accompany all copies of future rate filings and which must be present in order for a rate filing to be accepted as complete by the Commission.

The ALJ and parties did not address this matter in written documents. The Department did comment at oral argument indicating that it did not object to the removal of the official filing requirement status of the four items requested by NSP. However, the Department indicated that it did use the information and indicated that it would expect that the Company would file one copy of this information with the Commission, the Department, and the RUD-OAG on the same day that future rate filings are made.

The Commission recognizes that the information contained in the four items is substantial and the added burden that is placed on NSP in making rate filings. However, the Commission is also mindful that an in-depth review is difficult for the parties to NSP's rate proceedings if adequate information is not available very early in the process. In an effort to accommodate both concerns, the Commission will remove the requirement that the first four items be included as official filing requirements for the next rate case filing only. NSP will be directed to make single copies of the information available for the Commission, Department, and RUD-OAG on the same day of filing a rate case. NSP will be directed to include a notice with all copies of the next rate filing that such information is available upon request by any other interested parties.

M. Taxes

As discussed under Taxes in the Operating Income Statement section of this Order, the Commission accepted NSP's modification of the original filing to amortize the effects of the four pre-test year tax issues over two years. The Commission also accepts NSP's proposal to include the unamortized balance in test year rate base. That adjustment reduces test year rate base by $1,763,000.

N. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $2,373,335,000 as shown below (000's omitted):

Utility Plant in Service	$5,221,355
Less: Reserve for Depreciation	2,408,306
Net Utility Plant in Service	$2,813,049
Construction Work in Progress	141,327
Plant Held for Future Use	0
Accumulated Deferred Income Taxes	(590,770)
Working Capital	
Cash Working Capital	(78,300)
Materials and Supplies	86,729
Fuel	25,486
Prepayments	6,803
Other	(30,989)
TOTAL AVERAGE RATE BASE	$2,373,335

XII. OPERATING INCOME STATEMENT

In its initial filing, NSP proposed test year utility operating income, under present rates, of $170,570,000 based on test year operating revenue of $1,512,564,000. During the course of this proceeding, the Company made adjustments to its test year income statement in two updates, rebuttal testimony, a depreciation update, and its reply brief. In its reply brief, the Company proposed utility operating income of $167,095,000.

In order to delineate the changes from the initial filing to the Commission's finally determined test year operating income, the Commission will begin with the Company's initially filed utility operating income. Individual income and expense adjustments will be discussed below.

A. Employee Compensation

1. Introduction

The Company sought recovery of approximately $237,415,000 in employee cash compensation for the combined gas and electric utilities. Approximately $10 million of this amount represented sums potentially payable under an incentive compensation program. The program consists of six plans: an annual plan for employees in each branch of the Company's work force (bargaining, nonbargaining, management, and executive) and two long-term plans for officers and executives. Under the program a portion of every employee's compensation is contingent upon his or her organizational unit achieving quantifiable goals relating to safety, customer satisfaction, productivity, and cost control. Except for employees in the bargaining unit, eligibility for incentive compensation also depends upon achieving individual performance goals.

The Company claimed the incentive compensation program would help achieve two goals: (1) it would gradually reduce Company wage rates to the market median by avoiding the compounding effects of base salary increases; (2) it would reinforce employee behaviors the Company has determined are crucial to reaching its goal of becoming more customer-oriented. Parties challenged both wage rates and the reasonableness of the Company's incentive compensation program.

The Department urged the Commission to focus on wage levels as a whole as opposed to the design of individual compensation packages. The Department did, however, recommend disallowance of the costs of the long-term incentive plan for executives and the earnings per share component of the officers' annual plan, believing the first worked exclusively to the benefit of shareholders and the second risked weakening the commitment to the long-term so crucial to the operation of a public utility. The Department also contended the Company's overall wage levels were significantly above market and should be reduced by 2.37 percent for ratemaking purposes. The Department disputed the

Company's claim that its overall salary levels were similar to those of similar companies, arguing the Company's comparison group was not genuinely comparable. The Department contended Company salary levels as a whole were 7.37 percent above the market median.

The RUD-OAG, MEC, and SRA advocated disallowance of all costs attributable to the incentive compensation plan for the following reasons: (1) the plan as a whole, especially the executive and the long-term portions, seeks to transfer the risks of operation from shareholders to ratepayers and employees; (2) the plan's link between low rates and eligibility for incentive compensation is not adequately supported by a link between employee performance and rate levels; (3) the plan's requirement that departments spend their budgets, as well as not overspend them, fails to adequately protect ratepayers' interests in cost-cutting; (4) the plan is a "bonus" in disguise, and the Company has not demonstrated that a bonus is necessary to attract a work force capable of delivering high quality service at reasonable rates.

The Administrative Law Judge found NSP's overall compensation levels unreasonably high and that incentive compensation was the element raising them above market averages. ALJ Findings No. 271 and 274. He believed the Company should be granted some flexibility to pay above-market salaries and recommended rate recovery of overall wage levels up to 105 percent of the market median. He adjusted the Company's market median for defects in its comparison group and recommended an across-the-board disallowance of 2.37 percent of test year compensation expense.

He also found that properly designed incentive compensation plans were in the public interest; he did not find defects in the NSP plan justifying disallowance. He did express concern about the Company's retention of the option to decline to pay incentive compensation earned under the plan, an option management exercised in 1992. His decision to limit recoverability of overall compensation to 105 percent of the market median was based in part on the possibility of this happening again. ALJ Discussion, p. 60.

2. Commission Action

a. Summary

The Commission accepts and adopts the Administrative Law Judge's findings that the Company's employee compensation levels are unreasonably high and that the component that raises them above market averages is the incentive compensation plan. The Commission finds that the benefits of the incentive compensation plan are speculative while the drawbacks are real. Given the significant plan deficiencies noted below, the Commission will take the most straightforward course of action and disallow recovery of all expenses associated with the incentive compensation plan.

b. Overall Compensation Levels

The Company stated its overall wage levels were above its target, which was 100 percent of the market median, and that the incentive plan was one of the tools it was using to bring salaries into alignment with the market median. The Department placed current salaries at 107.37 percent of the market median. The Department also argued the Company's perception of the market median was skewed, because the companies with which it compared its wage scales were not genuinely comparable. The Administrative Law Judge characterized the Company's choice of comparable companies as demonstrating an "aggressive" recruitment policy and recommended the 2.37 percent overall disallowance advocated by the Department.

The Commission agrees with the Department that the companies with which NSP chose to compare its salaries, especially officers' and executives' salaries, were not truly comparable. NSP is a regional utility. The companies in the comparison group were national and international industrial companies and national utilities. All salaries in the comparison group were weighted equally, despite the fact that utility salaries are generally lower. The Commission therefore agrees with the Department and the ALJ that the comparison study is less than totally credible and has skewed NSP's calculations of the market median.

The Commission also accepts and adopts the ALJ's finding that NSP's base salaries are approximately equal to those paid in comparable markets and that any incentive compensation paid would raise them above market levels. Because the cost of the incentive plan is a useful proxy for the amount by which NSP salaries exceed market rates, and because of serious deficiencies in the incentive plan discussed below, the Commission will disallow the costs of the incentive plan. This does not mean, of course, that the Company must discontinue the plan. It merely means the Company cannot recover the costs of the plan from ratepayers.

The Commission disagrees with the Department and the Administrative Law Judge that the salary component of NSP's rates should reflect 105 percent of the adjusted market median. For any regulated utility, recovery of above-average expenses in any category requires explanation and justification. While the "just and reasonable" standard does not automatically translate into "average," that is a good starting point from which to analyze the reasonableness of claimed expenses. In this case the Commission sees no justification for higher than average salary expense.

The Commission appreciates the Company's claim that setting wage levels is a management prerogative the Commission should respect and uphold if at all possible. Clearly, determining wage rates is a key managerial function which seriously affects employee morale and the size of the labor pool available to the Company. At the same time, labor expense is a key component of utility rates. The Commission has a duty to examine every component of rates for prudence and reasonableness and to resolve any doubt in favor of the consumer. Minn. Stat. § 216B.03 (1992). The Commission concludes that managerial prerogative must yield to Commission oversight on the issue of what portion of labor expense is recoverable from ratepayers. Management may of course choose to pay salaries in excess of recoverable amounts.

The Commission has examined total test year labor costs, finds them higher than the market requires, and will disallow the incentive plan expenses which take them above market levels.

c. Incentive Plan Deficiencies

A major reason the Commission rejected the Company's 1991 incentive compensation plan was a Commission finding that the plan improperly transferred risks of operation from shareholders to ratepayers and Company employees.[3] This defect was more obvious in the 1991 plan, which made all incentive plan payments contingent upon Company earnings meeting a specified earnings per share threshold. The current plan, however, retains an earnings per share component in the officers' and executives' plan and in the long-term plans, which are available only to officers and executives.[4] The Commission continues to consider earnings per share thresholds an improper transfer of risk, since ratepayers bear the risks (the costs of incentive compensation) and shareholders reap the benefits (increased earnings per share).

The Commission also continues to believe earnings per share thresholds can jeopardize a utility's commitment to providing safe, reliable, economical service over the long-term by over-emphasizing short-term performance. In most private business contexts, short-term thinking is merely unfortunate. In the public utility context, it can create a public crisis.

Another defect in the plan is the large percentage (up to 30 percent and 40 percent) of executives' and officers' pay which can come from incentive compensation. These percentages are simply too high. Their stated purpose is to align officers' and executives' interests more closely with those of shareholders. While officers and executives clearly have a duty of loyalty to shareholders, they also have a duty to exercise independent judgment on behalf of the Company and to give regulators their

---

[3] <u>In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota</u>, Docket No. E-002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (November 27, 1991) at 55.

[4] The Company does not expect to meet the plans' earnings per share threshold in the test year and does not seek recovery of amounts attributable to those portions of the officers' and executives' plans. It does seek Commission concurrence in the plans' design, however.

full cooperation. Offering key decisionmakers large financial rewards for producing short-term shareholder benefits does not promote regulatory efficiency or the long-term fortunes of the Company. Since the public has an interest in ensuring the long-term viability and stability of the Company, this is a serious defect.

Another of the plan's serious defects is that the Company retains the right not to make incentive payments earned under the plan. Management exercised this prerogative in 1992 and did not disclaim its ability to do so in the future. This is a clear case of transferring risk from shareholders to ratepayers. If expenses are unexpectedly high or revenues unexpectedly low, shareholders can offset these losses with funds provided by ratepayers for the incentive compensation program. This runs contrary to the test year concept on which rates are based, and the Commission strongly disapproves.

The Commission also shares the concerns of the RUD-OAG and the SRA about two performance measures: the one linking incentive pay with low rates, as compared to the rates of other utilities, and the one penalizing departments for underspending their budgets by 2 percent or more. The first measure, linking low rates with incentive pay, seems arbitrary, since most NSP employees have little control over rate levels and since employee productivity is just one of many factors which cause rate differences between utilities. The second measure, spending within 2 percent of budget, seems counterproductive, since it would likely discourage managers from identifying and implementing cost-saving measures. It also appears to be a meaningless requirement; managers required to spend their budgets will do so, and that performance measure will always be met. The Commission's concern is not to quibble over details of plan design. The concern is that, to the extent that the performance measures of the plan are perfunctory and do not genuinely depend upon employee performance, the program is largely indistinguishable from a bonus program. While awarding bonuses is well within the discretion of Company management, rate recovery of such amounts is inappropriate given current salary expense.

Finally, the Company has failed to show the incentive program is necessary for dependable operations or that it would produce tangible benefits for ratepayers. The stated goals of the program -- better customer service, greater safety, higher productivity -- are all appropriate but are clearly core values every employee's performance is already expected to reflect. None of the goals or performance measures in the plan differ from the goals and performance measures that would apply without the plan. The Company's work force has performed well in the past without incentive compensation; the Company cited no drop in productivity or work quality making incentive compensation necessary. There is no evidence that an incentive compensation program is required to attract and retain a work force capable of delivering high quality electric service at reasonable rates.

With base salaries already at market levels, and work quality already high, the Commission cannot approve rate recovery of additional compensation in the form of an incentive plan.

The Commission has examined the incentive plan as a whole and concludes its benefits are speculative, its drawbacks are real, and its expense is not justified by any demonstrated need. Since NSP base salaries are already competitive in the relevant labor market, expenses associated with the incentive compensation plan will be disallowed.

The Commission finds that the electrical utility's jurisdictional Administrative & General expense should be reduced $9,948,000 for incentive compensation and $569,301 for the pension on the incentive compensation.

B. Financial Accounting Standard 106

1. Introduction

In 1990 the Financial Accounting Standards Board (FASB) issued a new standard for the accounting treatment of most non-pension post-employment benefits (Post-Retirement Benefits Other than Pensions, or PBOPs). The Board's Financial Accounting Standard (FAS) 106 called for companies to account for PBOPs on an accrual basis. Prior to the issuance of the standard, most Minnesota utilities, including NSP, had been recognizing these obligations on a cash (or pay-as-you-go) basis.

On September 22, 1992, the Commission issued its generic ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING in Docket No. U-999/CI-92-96. In that Order the Commission stated:

> The Commission adopts SFAS 106 accrual accounting for Minnesota utility recordkeeping and ratemaking purposes, subject to Commission review for prudence and reasonableness of the [PBOP] programs, expenses, and all calculations in future rate cases.
>
> Order at p. 6.

NSP adopted FAS 106 accrual accounting as of January 1, 1993.

In its rate case filing NSP sought recovery of its PBOP expenses, which consisted of three components:

1. The year's service cost, the present value of the future benefits earned by current employees during the year;

2. The interest cost, equal to the discount rate multiplied by the accumulated post-retirement benefit obligations; and

3. The amortization of the transition obligation, which is defined as the present value of the unfunded post-

retirement benefit obligation on the day FAS 106 is adopted.

In his report, the ALJ recommended allowing recovery of the three components of PBOP expenses.

2. Comments of the Parties

The parties raised a number of issues regarding FAS 106, including: recovery of the transition obligation; the prudence of the Company's PBOP plan; funding of the FAS 106 obligation; and the proper attribution period for FAS 106 accrual.

a. Recovery of the Transition Obligation

In their briefs, the Department, the RUD-OAG and the SRA advocated a sharing of the transition obligation and FAS 106 interest between ratepayers and shareholders.

On July 19, 1993, the Commission clarified its policy regarding a utility's recovery of a transition obligation arising from a change from pay-as-you-go to accrual accounting for PBOPs. In its ORDER AFTER RECONSIDERATION in the Minnegasco rate case, Docket No. G-008/GR-92-400, the Commission allowed Minnegasco recovery of the amortization of the transition obligation associated with prudent and reasonable FAS 106 obligations. The Commission later confirmed its policy in a similar decision regarding US WEST's recovery of the transition obligation associated with prudent and reasonable FAS 106 costs. ORDER AUTHORIZING RECOVERY OF COSTS OF IMPLEMENTING FINANCIAL ACCOUNTING STANDARD 106, Docket No. P-421/M-93-126 (July 21, 1993).

Recognizing that the Commission's policy would be equally applicable in the NSP rate cases, the Department, the RUD-OAG and the SRA all dropped their requests for a sharing of the transition obligation and FAS 106 interest between ratepayers and shareholders.

b. Prudence of the FAS 106 Costs

In his report, the ALJ stated that the Company had met its burden of proof regarding the prudence of its FAS 106 expenses. The ALJ found that the FAS 106 costs were prudent and reasonable, and recommended that any intervenor's challenge to prudence be dismissed.

The RUD-OAG stated that the prudence of the Company's FAS 106 costs could not be proven. The Department stated that it did not believe that the level or nature of the FAS 106 expenses were unreasonable. The SRA recommended that the Commission find that the Company's FAS 106 costs were at least partially imprudent, because the Company failed to switch to accrual accounting before January 1, 1993, and because the Company's pre-FAS 106 PBOP costs were too high.

c. Funding of the FAS 106 Obligation

The ALJ found that the Company should fund its FAS 106 obligations in an external Voluntary Employee's Beneficiary Association (VEBA) trust, to the extent that such funding is tax-advantaged.

The Department advocated 100 percent external funding of the Company's FAS 106 obligations, to ensure security of the funds for ratepayers.

NSP argued that it should be allowed to fund its FAS 106 obligations internally. The Company stated that this option is less costly than external funding, provides more flexibility for investments, and can be monitored sufficiently by the Commission to provide security for ratepayers. The Company stated further that it preferred a tax-advantaged VEBA trust, should it be required by the Commission to maintain external funding.

d. The Attribution Period for the PBOP Plan

The attribution period is the time period over which actuaries measure the service of an employee who will receive PBOPs. The attribution period is used in calculating the present value of an active employee's expected PBOP obligation.

Under NSP's proposed plan, the SFAS 106 accrual would be calculated using an attribution period which begins when the employee is first eligible for PBOP benefits and ends when the employee achieves full eligibility for benefits. This is the definition of attribution period required by the FASB for FAS 106 financial reporting.

The ALJ agreed with NSP's proposed attribution period for FAS 106 obligations.

The Department and the SRA recommended that the attribution period end not with the onset of eligibility, but with the date of expected retirement. According to these intervenors, this change would reduce costs to ratepayers, and would create a better matching of costs with service provided to ratepayers.

3. Commission Action

a. Recovery of FAS 106 Costs

The Commission agrees with the ALJ that the Company has met the burden of proving that its FAS 106 expenses were prudent and reasonable costs of providing utility service. Testimony showed that the Company's plan benefits and costs were comparable to other utilities in the Twin Cities and around the country. As the ALJ stated at p. 43 of his report, "evidence demonstrates that NSP's retiree medical benefits, and benefits for current employees are near the median in the various comparison groups."

The evidence also shows that the Company took steps, such as the initiation of managed care, to control PBOP expenses in the face of increasing health care costs. NSP downscaled its employee PBOP benefits, while remaining aware of the vulnerability of its retired employees.

The Commission does not agree with the SRA that the timing of the Company's change to accrual accounting indicates that its FAS 106 costs were imprudent. Prior to the establishment of FAS 106, the prevailing, prudent business practice was to account for PBOP costs under the pay-as-you-go method rather than the accrual method. Since the Commission's September 22, 1992 generic decision to sanction accrual accounting for ratemaking purposes, the Company changed to FAS 106 accounting and conformed to the requirements of the Commission's decision. Nothing in the Company's timing or accounting treatment rendered its otherwise reasonable PBOP expenses imprudent.

There is nothing in the record to support the SRA's contention that the Company's pre-FAS 106 PBOP costs were excessive. Even if such evidence had existed, it is the Company's **present** FAS 106 plan, not its past plan, which is before the Commission for consideration. Quoting the ALJ's comments on the same issue, the Commission stated at p. 10 of its ORDER AFTER RECONSIDERATION in the Minnegasco rate case, "the only plan under scrutiny for prudence is that with an effective date of January 1, 1993. There is no direct challenge of the cost levels in that plan."

Having found that the Company's proposed PBOP costs were prudent and reasonable, the Commission will approve the costs for use in setting rates in this docket. As the Commission explained in the Minnegasco reconsideration Order, the transition obligation is an integral part of the move to FAS 106 accounting; approval of the transition obligation is linked to approval of the costs. As the Commission stated at p. 10 of the Minnegasco reconsideration Order, "[a] transition obligation naturally and inevitably arose from the one time accounting change from cash basis to accrual basis for PBOPs." The Commission will approve full recovery of the amortized transition obligation component of PBOP costs.

Lastly, the Commission finds that the Company's interest costs associated with FAS 106 accrual accounting are reasonable operating costs. The Commission thus approves recovery of this third component of the Company's FAS 106 costs.

b. Funding of the FAS 106 Obligation

The Commission agrees with the ALJ that the benefits of external funding of the FAS 106 obligation outweigh any incremental costs incurred. The additional administrative costs for external funding have been estimated at $633,000 for the electric utility and $63,000 for the gas utility. The Commission also recognizes that external funding will cause some loss of investment flexibility and options. These drawbacks, however, are outweighed by the additional security for ratepayers which external funding will bring about. External funding will help ensure that PBOP funds are in place when they are needed, a time which is often in the distant future.

The Commission agrees with the general consensus that external funding should be required under the VEBA form. It is in the best interests of ratepayers to limit the requirement of the external, VEBA funding to the extent that the tax benefits of such funding outweigh the associated expenses. The Commission will require that the external funding mechanism be in place by the time the Company files its next general rate case. By limiting the funding requirement to the extent of tax advantage, and allowing a startup period, the Commission intends to move the process to greater ratepayer security while allowing the Company to develop the most advantageous funding plan.

c. The Attribution Period

The attribution period is the time period over which actuaries measure the service of an employee who will receive PBOPs. The attribution period is used to determine the present value of an active employee's expected benefit obligation.

The FASB requires an attribution period which begins with employee hiring and ends at the date of full employee eligibility for benefits. The Commission agrees with the ALJ that in this set of circumstances it is best to set an attribution period for ratemaking purposes which is parallel to the attribution period established by the FASB for financial reporting purposes. The Commission is not in any way controlled by the FASB in its ratemaking decisions; however, when good reasons otherwise indicate parallel accounting treatment, such treatment is the most useful and least burdensome for the utility. In this case, the Commission believes that there are good reasons for adopting the FASB method of calculating the attribution period.

An attribution period which ends at the date of full employee eligibility, rather than the employee's projected retirement date, holds less risk of underfunding. Employees who retire at their earliest eligibility age, often 55, are not covered by Medicare until they reach the age of 65. These employees pose a possibility of significant cost to the system. Thus, an attribution period which accrues PBOP costs until the point of eligibility should fund the PBOP system more accurately and securely than an attribution period which accrues costs until a projected retirement date.

The FASB carefully considered extending the attribution period to the projected date of retirement but decided against that method. The FASB stated that an attribution period set at the employee's retirement eligibility date represents an accurate picture of the employment agreement between employer and employee. The Board also decided that the attribution period it approved represents the best possible match between employee service and the PBOP benefits accrued. While the FASB decisions are not binding upon the Commission, they represent carefully reasoned determinations and are persuasive in this context.

Extension of the attribution period, as advocated by the Department and the SRA, would result in decreased costs of $536,000 for the electric utility and $53,649 for the gas utility. For the reasons stated, the Commission finds that the benefits to ratepayers outweigh the minimal rate impact. The Commission will approve the method of calculating the attribution period proposed by the Company and recommended by the ALJ.

d. Deferred Accounting

In the ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING (September 22, 1992) in In the Matter of the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106, Docket No. U-999/CI-92-96, companies were permitted a deferred accounting mechanism for the increased costs, beginning January 1, 1993. The Order set certain alternative time limits for the deferral, including the issue date of the Order setting final rates following a general rate case. The Commission ordered that interim rate recovery would not be allowed during the deferred accounting period.

The Commission's decision in the current docket results in the inclusion of SFAS 106 costs and an amortization of the amount deferred during the test year in final rates. In calculating the interim rate refund, there may be the potential for double-recovery of the deferred test year SFAS 106 cost. The Commission will direct the Company to address the potential double-recovery question and to propose a method to avoid double-recovery, if any, in its compliance filing.

C. Unbilled Revenues

1. Historical and Factual Background

As a practical matter, it is impossible for the Company to read every meter on the last day of each year. Instead, the Company reads meters throughout the month, and bills customers on a cyclical basis throughout the month. The usage from each customer's meter reading date to the end of the month remains unbilled until the meter is read and the bill prepared in the following month. The term "unbilled revenues" refers to revenues which the Company has earned between the most recent meter reading date and the end of the month.

NSP included in its filing the test year unbilled revenues (the difference in the unbilled revenues recorded at the beginning of the test year and the end of the test year).

In 1992, NSP recognized for financial reporting purposes the unbilled revenues as of December 31, 1991. The total amount of unbilled revenue recorded for Minnesota, North Dakota and South Dakota was $76.1 million.

2. Positions of the Parties and Recommendation of ALJ

The RUD-OAG proposed that the Commission recognize the accumulated unbilled revenue for regulatory purposes as extraordinary income and amortize it over four years. The RUD-OAG argued that this income was derived from the sale of gas and is extraordinary in that it does not recur as normal test year income.

The RUD-OAG based its claim that the extraordinary revenue should be recognized for ratemaking purposes on several factors. First, NSP has recognized its accumulated unbilled revenues as revenue for financial purposes. Second, regulatory recognition of the cumulative effect of unbilled revenues represents a change of regulatory accounting that is more consistent with regulatory expense accounting. Third, since every other stakeholder in this income has received benefits from the income, it is only fair and symmetrical that ratepayers receive this credit as well. Finally, this recognition of the utility income from unbilled revenues is consistent with the accounting requested by NSP for the transitional FAS 106 expenses.

The RUD-OAG recommended amortizing $1,541,240 (gas) and $55,570,231 (electric), the unbilled revenue at the end of 1990 over four years. The test year adjustment would be $386,000 (gas) and $13,892,500 (electric). The use of this time frame (December 1990) precludes any question of double-counting the test year unbilled revenues.

The RUD-OAG proposed two alternative solutions if the Commission does not accept the amortization proposal. First, the unbilled revenue amount adjusted for taxes ($33,082,070) could be removed from the equity portion of NSP's capital structure. Or second, the rate base could be reduced by the amount of bookings (the 12-31-91 unbilled revenue) so that ratepayers do not pay a return on the booked amounts.

However, the RUD-OAG did not except to the ALJ's findings on the unbilled revenue issue.

The Department's recommended adjustments apply only to the electric utility. The Minnesota electric jurisdiction unbilled revenues recorded by NSP as of January 1, 1992 were $50,578,023. The Department recommended that for ratemaking one-half of these revenues amortized over five years be recognized in test year revenues as extraordinary revenues. The test year adjustment would be $5,057,802. The Department argued that while NSP recognized these revenues for financial purposes, they have not been recognized for ratemaking purposes. The Department's adjustment is an attempt to reconcile the recognition of these revenues on the books and the actual receipt of these revenues with the recognition of these revenues for ratemaking purposes.

The Department argued that NSP received the unbilled revenue because NSP's accounting and ratemaking books in the past did not account for the unbilled revenue. Therefore, NSP's revenue requirements in the past rate cases were greater than they would have been had the unbilled method of accounting been used. The Department made illustrative calculations to demonstrate that the use of the billed method of accounting resulted in an under-reflection of revenues in the ratemaking process in the past. The Department used the amount actually booked as a proxy for the effects of the change in accounting methods. The Department contended that now that the accounting methods have been changed there needs to be an adjustment to reconcile the regulated books with the financial books, and to provide ratepayers with a proxy of the revenues that were ignored in ratemaking in the past, in effect a "catch-up" resulting from the change in accounting methods. Since ratepayers paid the expenses (related to the unbilled revenue) when they were booked, they should get credit for the revenues now that they are booked.

NSP argued that the unbilled revenues recorded by NSP in 1992 for financial purposes have already been included in rates. By adjusting NSP's 1991 test year revenue deficiency for test year unbilled revenue, the Commission included the year end 1991 unbilled revenue amount in rates for that test year. Including the change in unbilled during the year is in effect adding all the year end unbilled revenue and subtracting all the beginning of year unbilled revenues. If the Commission were to accept the Department's and RUD-OAG's proposed adjustment it would be using the same revenues that were used to reduce NSP's test year deficiency in 1991 a second time in 1993 to reduce the deficiency NSP is experiencing in the current year.

The Company argued that on page 47 of the Commission's November 27, 1991 Order in Docket No. E-002/GR-91-001, the Commission determined that including pre-test year unbilled revenues results in a mismatch, stating:

> The Commission also agrees with the ALJ's recommendation regarding the RUD-OAG's proposed inclusion of an amortized portion of accrued unbilled revenues. Unbilled pre-test year revenues should not be included in test year revenues, because to do so would be to match twelve months' costs with more than twelve months' revenues. Amortization of these revenues would not change the fact that they are improperly included in test year revenues. The Commission finds that pre-test year revenues should not be included in test year revenues.

In Peoples Natural Gas, Docket No. G-011/GR-92-132, the Commission stated:

> [T]he unbilled revenue issue raised by the RUD-OAG involves a proposed recognition of revenues which the Commission has consistently found do not belong

to ratepayers.

The year end 1990 unbilled electric revenues and the pre-test year 1985 unbilled gas revenues that the RUD-OAG proposes to include in this case are the identical revenues which the RUD-OAG sought to have included in NSP's 1991 electric rate case and NSP's 1986 gas case as pre-test year accumulated unbilled revenues. The Commission rejected the RUD-OAG's proposal in both cases. NSP contended that to the extent that the RUD-OAG believed that the Commission's decision in either of those Orders was incorrect it was entitled to seek a reversal by means of pursuing reconsideration with the Commission and, if necessary, an appeal to the courts. It is inappropriate for the RUD-OAG to attack the earlier decisions at this time.

NSP argued that the fact that NSP recorded unbilled revenues on its financial books does not impact the proper ratemaking treatment. In Docket No. E-002/GR-85-558, Order After Reconsideration, at 3 (October 20, 1986) the Commission stated:

> The amount of $3.7 million does not represent a liability owed to ratepayers. It will not appear on the Company's books unless and until the accounting change to begin recording unbilled revenues is adopted. If the adjustment were to acquire form in the accounts of the Company, its substance could be examined for what it really is - a one-time extraordinary adjustment to revenues. That increment to existing revenues during a test year would first be a non-recurring event that did not reflect ordinary operations. Second, it would not represent revenues from test year sales. Third, it would not be an offset to any rate base or expense item found in the test year. As such, the adjustment is not of a character that logically would be included in test year revenues.

NSP argued that the Department's stated rationale for its proposed adjustment plainly violates the prohibition on retroactive ratemaking. The basis of the adjustment is the allegation that NSP collected excessive rates from ratepayers in prior periods because ratemaking did not use the unbilled method of accounting.

The RUD-OAG's first alternative proposal to adjust NSP's capital structure is not justified. Even with the accounting change included, NSP's actual earnings in 1992 resulted in returns below the level authorized by the Commission. NSP noted that none of the intervenors, the RUD-OAG included, have suggested that NSP's proposed capital structure, including its equity component, is unreasonable.

The RUD-OAG's second alternative proposal to adjust NSP's rate base is also not justified. An adjustment to rate base would be appropriate if the RUD-OAG would demonstrate that NSP ratepayers supplied cash to the Company in advance of receiving service. This is not the case with unbilled revenues. To the contrary, at the time unbilled revenues were recorded on NSP's books, shareholders had advanced the cash necessary to fund the costs of service provided.

The ALJ concluded that there is no need for "consistency" between the FAS 106 issue and unbilled revenue. He recommended that each issue should be decided on its own merits.

The ALJ accepted the Company's position and recommended that the Department recommendation and the RUD-OAG recommendation and alternatives be rejected. He stated that the arguments in favor of including "accumulated" unbilled revenues in this rate case have all been dealt with by the Commission in the past including the financial reporting.

3. Commission Analysis

The Commission agrees with the ALJ that it is not necessary to reach identical decisions for the FAS 106 issue and unbilled revenue issue. Other than the fact that they both are the result of a change in accounting, they are totally unrelated issues. The Commission will decide each on its own merits.

The Commission also agrees with the ALJ that the RUD-OAG and Department have presented no arguments that the Commission has not already thoroughly considered in numerous past proceedings and dismissed. As referred to above, the Commission has determined:

1. that pre-test unbilled revenues do not belong to ratepayers (Docket No G-011/GR-92-132),

2. that inclusion of pre-test year unbilled revenues in the test year will result in a mismatch, with more than twelve months revenue and only twelve months costs (Docket No. E-002/GR-91-001), and

3. that the recording on financial books of pre-test year unbilled revenues does not result in test year revenues (Docket No E-002/GR-85-558).

The Commission also determined that unbilled revenues do not accumulate in Docket No. E-002/GR-85-558, Order at 35:

> For example, the Company, the RUG-AG, and the ALJ have implied that the unbilled revenue at the beginning of the test year includes revenues that have been unbilled from the very inception of the Company. In the Commission's view, that characterization is misleading and inaccurate. Generally what is unbilled at the end of any month is the electricity that has been consumed since the prior meter reading date.

The Department and RUD-OAG argued that because the Company booked the unbilled revenue for financial purposes, extraordinary income was created and as such must be included in the test year. The Commission's Order After Reconsideration at 3 (October 20, 1986) in Docket No. E-002/GR-85-558, concluded that this revenue, while extraordinary, is not of a character that logically would be included in test year revenues. The Commission confirms its prior conclusion. The Commission also notes that simply the fact that it is extraordinary does not in and of itself mean that it should automatically be included in, or excluded from rates. An extraordinary revenue or cost must be evaluated on its own merits and a decision made on that basis.

The Department and RUD-OAG argued that the pre-test year unbilled revenues have never been considered for rates and now that the Company has recorded them for financial purposes, ratepayers must be given credit for them. First, the Commission has considered pre-test year unbilled revenues in prior rate cases and consistently rejected their inclusion in test year revenues. Second, the amount of revenue calculated for test year purposes is the result of multiplying the sales and customer forecast times the tariffed rates. The sales and customer forecasts have been considered in prior rate cases. The Commission determined what sales and customer forecast (and therefore revenues) should be used that would result in just and reasonable rates. Any argument that unbilled revenues were not considered and should be included in this test year to rectify that assumes that a correction should be made to the accepted forecast (and revenues). The Commission does not believe that such a correction would be justifiable or necessary.

Based on the above reasoning, the Commission finds that pre-test year unbilled revenues should not be included in this test year.

D. Regulated/Non-regulated Allocations

MEC proposed that NSP be required to follow the cost allocation principles adopted by the Federal Communications Commission (FCC) which result in fully allocated costs, where each unit bears its full share of all the costs. This is the opposite of incremental costing where each unit bears only the additional costs caused by its operation. As a utility develops businesses that are accounted for below the line or are non-regulated, MEC contended that it is important that all costs be fully allocated to protect ratepayer interests.

MEC argued that the Commission's November 10, 1992 Order in Docket No. G-008/C-91-942 that required Minnegasco to adopt FCC guidelines also requires NSP to adopt the FCC guidelines. MEC contended that NSP is not following the FCC cost allocation methodology.

MEC argued that as a result of not following the FCC guidelines:

1. NSP will not allocate significant customer-related

costs caused by NSP's non-regulated operations, thereby subsidizing non-regulated operations.

2. NSP will arbitrarily allocate a portion of its common administrative and general cost pool without any factual basis for the use of that level of allocations.

3. NSP will use its revenue allocation to allocate indirect common costs even though the revenue allocation has no relationship whatsoever to costs and will result in subsidization of non-regulated operation.

MEC argued that if the Commission required NSP to follow FCC cost allocation guidelines the result would be to eliminate ratepayer subsidization on non-regulated operations in the amount of approximately $2.1 million for Minnesota electric. MEC did not quantify the effect on the gas utility.

The Company argued that MEC's allegations are unfounded and stem from a fundamental misunderstanding of NSP's system. NSP's cost allocation system uses the same approach as that adopted by the FCC and meets the principles contained in the FCC regulations. NSP explained that its cost allocation system is composed of a three-step process. First, costs incurred directly for non-regulated activities are directly charged to special accounts which remove those costs from regulated operations. Second, overhead costs attributable to costs which are directly assigned to non-regulated operations are allocated in the system. Third, the non-regulated operations are allocated a portion of joint and common costs. NSP argued that the relevant issue in this case is whether the cost allocation system used by NSP produces reasonable, adaptable, and consistent results.

The Department framed its investigation of NSP's cost allocations between regulated and non-regulated operations with the Minnegasco cost allocation Order in mind. The investigation focused on three issues:

* Does NSP identify and isolate all unregulated investments?

* Does NSP identify and assign direct expenses clearly attributable to unregulated operations?

* Does NSP develop and implement appropriate methods of allocating joint and common costs?

Though it did except to some of NSP's allocators, the Department concluded that the answer to all three questions was "yes." The Department concluded that NSP implemented appropriate controls to identify and separate the Company's investments in unregulated activities and that a review of a large sample of items indicated that most items were being charged properly.

The Department argued that MEC has improperly equated following FCC principles with following the letter of FCC rules. The Department did determine that NSP's methods are consistent with FCC guidelines. The Commission did not and could not order all Minnesota utilities to follow FCC allocation rules in the Minnegasco case. To do so would have been an improper rulemaking. The Department stated that it appears as if MEC is chiefly concerned with using the exact terminology contained in the FCC cost allocation rules, while the Department is evaluating whether other methods achieve similar reasonable results.

The Department recommended changes in the allocable percentage factors for eight departments which in its opinion more closely reflect the relationship to non-regulated operations. The Department also recommended using an R (revenue) allocator in place of an I (investment) allocator because some operations do not have an investment but would receive benefits from regulated functions.

The Department concluded that with its recommended adjustments, which NSP agreed to accept, the allocation system will result in just and reasonable rates. The Department's recommended adjustments would reduce electric expenses by $796,000.

The ALJ agreed with the Company and the Department that NSP allocates costs in accordance with a hierarchy similar to that prescribed by the FCC cost allocation rules. Adjusting electric expenses by $796,000 as recommended by the Department will result in just and reasonable rates.

The Commission agrees with the Company, Department, and ALJ that the cost allocation methodology used by the Company is acceptable and results in reasonable allocations for the purpose of setting rates in this proceeding. The Commission finds that expenses should be reduced by $796,000, increasing net income by $474,000.

E. Rate Case Expense

NSP did not include an amount for rate case expense in the original filing. Instead, NSP sought recovery of the entire $868,818 amount through interim rates. In the ORDER SETTING INTERIM RATES, December 31, 1992, the Commission rejected that proposal. The Commission indicated it would be premature to allow recovery of the full amount through interim rates, since the costs incurred had not received the benefit of review in the full rate proceeding.

In its February 17, 1993 update, NSP proposed amortizing the $868,818 over two years, with the $217,000 unamortized balance included in rate base. However, in its brief, NSP indicated that it preferred receiving the entire amount of rate case expense as a reduction of the interim rate refund, with the amortization method employed only if there is an insufficient refund to achieve full reimbursement.

The Company stated that the Commission deemed it appropriate to include unamortized rate case expenses in rate base in the 1987 electric case. It argued that a rate case is not primarily for the benefit of the shareholders. The rate case is a process necessary to fulfill the service obligation of a public utility. Customers expect safe, reliable, and dependable service at a reasonable price (which is regulated by the Commission). Rate case expenses are simply a cost of doing business for an industry that is regulated. It is necessary to properly recognize the time value of money via the carrying cost on regulated expense deferrals.

The Department recommended that the full amount of rate case expense be recovered from the refund of interim rates, if a sufficient refund is ordered. If there is no refund, the Department recommended that rate case expense be amortized over two years, with the unamortized balance excluded from rate base. Regarding the unamortized balance, the Department argued that rate cases are filed primarily for the benefit of shareholders (i.e. to maintain or increase earnings). Ratepayers should not be required to provide a return on these expenses during the amortization period. In NSP's 1986 gas rate case, the Commission denied rate base treatment for the unamortized rate case expenses related to the test year, stating that, "the historical evidence of more than full recovery indicates that an extraordinary adjustment to put the unamortized balance in rate base would unduly burden ratepayers and is not necessary to protect the shareholders." The Department also stated that NSP had overrecovered rate case costs from the 1986 case. The Department stated that the payments for rate case costs can occur after the test year even though they are included in the test year.

No party questioned the reasonableness of the expense.

The ALJ recommended that the full amount of rate case expense be deducted from the refund. If there is no refund, the ALJ recommended the two-year amortization. The ALJ recommended that the unamortized balance be excluded from rate base as would be consistent with the Commission's precedent in NSP, Docket No. G-002/GR-86-160.

The Commission finds that allowing the recovery of rate case expenses from the refund is the preferred method. By allowing recovery through the refund, the Company receives the full amount of its expenses; no more, no less.

When the amortization method is employed, estimations must be made. Because rate case expense is incurred only in years in which a rate case is filed, the amount of expense included in the test year must be adjusted to reflect the fact that the expense is not incurred annually. To include the full amount of the expense in the test year would lead to rates permitting the Company to recover the full amount of rate case expense each and every year until it files its next rate case. In order to avoid excess recovery, an amortization is made in an attempt to spread the cost over the period of time which the rates will be in effect. If the amortization period is too long, underrecovery may result, and if the amortization period is too short, overrecovery may result. Allowing the full amount to be deducted from the interim refund avoids such estimations.

Based on the decisions in this order, there will be a refund of interim rates sufficient to allow the deduction of the rate case expense. The Commission will direct NSP to deduct $868,818 from the refund due. Since the Commission is using the original filing as its starting point and no rate case expense was included in the original filing, no adjustment is necessary.

To evaluate the accuracy of NSP's estimate of rate case expenses, the Commission will require the Company to report its actual rate case expenditures 60 days after all administrative review of this Order has been exhausted.

Should it develop that there is no refund, or a refund of insufficient amount to cover the rate case expenses, the Commission will direct NSP to amortize the rate case expense over two years and include the $217,000 unamortized balance in rate base. Recent history suggests that NSP is likely to file a rate case on a two-year cycle. The Commission finds that the two-year amortization is reasonable.

The Department and the ALJ cited the Commission's decision in NSP's 1986 rate case (Docket No. G-002/GR-86-160) as precedent for the proposition that the unamortized balance should not be included in the rate base. However, the Commission's treatment of the unamortized balance in that matter has little precedential value. On reconsideration, all rate case costs were recovered from the refund, mooting the issue of whether unamortized rate case cost belonged in the rate base. Docket No. G-002/GR-86-160, ORDER AFTER RECONSIDERATION (April 1, 1987).

Facing the issue directly, the Commission finds that the unamortized balance of the rate case expenses should be included in rate base as proposed by NSP. The issue turns on whether rate case expenses are properly characterized as operating expenses, as argued by the Department, or plant expenses, as argued by the Company. The Commission concludes that rate case expenses are more similar to the Company's investment in plant. NSP's shareholders have supplied working capital to pay rate case expenses and must wait until the money is ultimately recovered from customers. Accordingly, rate case expenses should be treated similarly to the Company's investment in plant, i.e. recovered over a period of years with the unamortized balance in rate base.

The Commission also finds that if the Company were to receive the full amount of the costs as a deduction from the refund, the Company would enjoy the benefit of $868,818 in current funds. If the costs are amortized over a period of two years, the Company will not receive the full amount of the funds until two years from now. Absent a return on the unamortized balance achieved through its inclusion in the rate base, the Company would not be in the same financial position under the amortization method as it would be by deducting the costs from the refund. The receipt of funds two years in the future is not the same as the receipt of funds currently when due consideration is given for the time value of money.

F. Advertising

In its original filing, the Company included test year advertising expense of $2,391,723. The Company included samples of both included and excluded advertising.

The Department reviewed the costs for prudency and compliance with Minnesota statutes. Based on its review, the Department recommended no adjustment, indicating that NSP does not seek recovery of advertising disallowed by Minn. Stat. 216B.16, subd. 8, or for non-jurisdictional costs.

The ALJ recommended NSP's advertising expenses as reasonable. Based on the assurances by the Department and the recommendation by the ALJ, the Commission will accept the advertising expense as appropriately adjusted to exclude non-jurisdictional and statutorily disallowed costs.

G. Marketing

NSP has offered a number of electric marketing programs throughout the test year. The programs include dual fuel heating, commercial cooking, snow melting, thermal storage heating, material handling, greenhouse lighting, infrared heating, security lighting, supplemental heating, and industrial drying and curing. These programs offer customers alternative energy services. Many of them are designed to sell additional electricity off-peak in order to smooth out NSP's load curve and spread fixed costs over more sales. NSP included $336,383 for its electric marketing programs in operating expenses.

Based on a cost-benefit analysis, the Department recommended excluding $318,298 in marketing expenses (all programs except the security lighting program). The Department's cost-benefit analysis differs from NSP's in that the Department considers winter capacity costs and long-term marginal capacity costs, and also uses an externality cost of $0.01/kWh. The ALJ agreed that, based on the Department's cost-benefit analysis, these amounts should be excluded.

The Commission finds that it is sound public policy to look at a cost-benefit analysis in the case of marketing programs, which will almost certainly result in future increases to NSP's load and potential acceleration of new capacity, including winter peaking capacity. Although the Commission makes no finding here as to the appropriateness of the Department's externality cost, the Commission believes that it is inappropriate to encourage consumers to increase electricity consumption unless the benefits of that increase clearly exceed all costs, including the potential costs to the environment.

The Commission is persuaded by the Department's cost-benefit analysis that $318,298 should be excluded from test year expenses for marketing programs which are not cost-effective.

H. Economic Development

NSP included $305,000 in test year operating expenses for economic development. This represents 50 percent of the test year 1993 budgeted economic development costs, including advertising, for Minnesota. The Department reviewed each of the Company's economic development programs and recommended three adjustments to NSP's request: the Commission should disallow $53,639 for the Target Marketing program, which was not cost-effective under the Department's analysis; the Commission should disallow $29,889 for the Industrial Land and Parks program, for which NSP was unable to provide an estimate of potential benefits; and the Commission should permit NSP to recover 100 percent (an additional $65,528) for the Area Development Rates (ADR) program, which is a Commission-approved program.

The ALJ recommended that the Company be permitted to recover 100 percent of the ADR program, and 50 percent of the remaining economic development expenses. The ALJ reasoned that because the economic development program was cost-effective overall, it was irrelevant that certain programs were not cost-effective.

Minn. Stat. § 216B.16, subd. 13 (1992) permits the Commission to allow a utility to recover from ratepayers the expenses incurred in economic and community development. In Docket E-002/GR-91-001, the Commission permitted NSP to recover 50 percent of its economic development expenses, based on the indication of legislative intent to facilitate economic development programs and a finding that both ratepayers and shareholders benefit from successful economic development programs. In addition, the Commission found that the benefits of a successful economic development program are indirect and difficult to quantify.[5]

The Commission finds that it is appropriate for NSP to recover 50 percent of its entire economic development program (including the ADR), or $305,000. If a rigorous program-by-program cost-effectiveness analysis had been conducted, it could be argued that the Company should recover 100 percent of its expenditures for programs which proved cost effective and nothing for those which did not. In lieu of such a program-by-program cost-

---

[5] In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket E-002/GR-91-001, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (November 27, 1991) pages 41 and 42.

effectiveness analysis and for administrative convenience, the Commission is reluctant to single out individual programs for separate treatment. Based on its review, a 50 percent recovery rate across all programs appears reasonable.

I. Conservation

1. Test Year CIP Budget

NSP initially proposed a test year Conservation Improvement Program (CIP) budget of $41,615,561. This included Department-approved programs of $35,431,747 as of October 1, 1992, plus additional budgeted funds to reflect anticipated new projects that were expected to be filed with the Department after filing this rate case. The Department argued that only approved programs should be permitted in the test year CIP budget, but recommended that the Company be permitted to update its CIP budget up until the time of the reply brief.

At the time of its reply brief, NSP had Department approvals for projects totalling $40,401,787. The Company argued that the Commission should use the most up-to-date budget for CIP expenditures, and recommended incorporating approved expenditures into the CIP budget up until August 20, 1993. On exceptions, NSP identified an additional $934,593 in approvals which had occurred since June 4, 1993, for a CIP test year budget to $41,336,380.

The ALJ found that the appropriate cut-off for inclusion of approved CIP projects in budgets should be June 4, 1993 (the date of the reply brief). He recommended a test year CIP budget of $40,401,787.

The Commission finds that $40,401,787 is the appropriate test year CIP budget to use for calculation of NSP's conservation cost recovery charge (CCRC). Adding approved projects beyond that date would require the Commission to take administrative notice of other proceedings and allow parties to comment. Because conservation expenditures continue to be tracked, the Company is not disadvantaged by a failure to include budget approvals which occurred after the official close of the record in this case. If NSP's conservation expenditures are greater than its collections, it will be permitted to recover the additional costs, with carrying charges, in a future rate proceeding.

In Docket No. E-002/M-90-1159, the Commission has approved a Demand-Side Management (DSM) financial incentive for NSP that allows NSP to amortize its direct and indirect impact projects over five years and earn its allowed rate of return, plus up to a five percent bonus return on equity, on the unamortized balance.[6]

---

[6] See In the Matter of the Proposal of Northern States Power Company's Electric Utility for a Demand-Side Management Incentive Mechanism, Docket No. E-002/M-90-1159, ORDER APPROVING PROPOSAL AND REQUIRING FURTHER FILINGS (March 19, 1991) and ORDER

Research, development and administrative expenses will continue to be expensed in the year incurred. The Company

---

APPROVING COST-EFFECTIVENESS, PERFORMANCE AND EVALUATION PLANS (January 3, 1992).

will also be permitted to recover 50 percent of lost margins due to interruptible sales over the test year.

The Commission finds that the CCRC should be calculated using the elements of the Company's DSM Financial Incentive. The Company will have direct and indirect impact expenditures of $35,029,728 and research, development and administrative expenses of $5,372,059. Using the financial incentive mechanism, NSP's CCRC will be set to recover revenues of $21,172,766. Projected sales for the test year Including unbilled sales but excluding Interdepartmental Sales) are 25,063,952 MWh. The Commission finds that the appropriate CCRC is $0.00084475 per kWh.

Basing test year CIP budget expenses at $40,401,787 increases test year net income $666,000 over the initially filed amount.

2. CIP Tracker Balance

NSP's final request was that it be permitted to recover $625,730 which is the difference between tracker collections and expenditures, plus all approved financial incentives and lost margin recovery, as of December 31, 1992. It proposed that the tracker balance be deducted from any interim rate refund, or amortized over a two-year period if no interim rate refund exists. No party objected to the recovery of these amounts.

The Commission finds that NSP should recover the full CIP Tracker balance of $625,730. Allowance of these amounts is consistent with Minn. Stat. § 216B.241 (1992) and with Minn. Stat. § 216B.16, subd. 6b (1992), which states as follows:

> All investments and expenses of a public utility ...incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments and expenses were directly made or incurred by the utility in furnishing electric service.

Recovery of the full tracker balance is also consistent with Minn. Stat. § 216B.03 (1992), which requires the Commission to set rates to encourage energy conservation.

3. Conservation Plan

When NSP filed this case, it was required under Minn. Stat. § 216B.16, subd. 1 to file a Conservation Plan with its rate filing. NSP's Conservation Plan included an expenditure level of $37,481,747 to cover DSM activities. Programs planned for 1993 will generate 231,291 MWh in savings on an annual basis and 141 MW of demand savings.

The Department and the ALJ recommended that the Commission accept NSP's Conservation Plan as adequate to meet the requirements of Minn. Stat. § 216B.16, subd. 1.

The Commission agrees with the Department and the ALJ and accepts NSP's Conservation Plan.

J. Manitoba Hydro

NSP sought to include as test year expenses twelve months of purchased power demand charges that it will incur pursuant to a 500 MW participation power agreement with Manitoba Hydro Electric Board. The agreement started May 1, 1993. According to its terms, the agreement will be in effect for twelve years. Because the Company chose a test year beginning January 1, 1993, four months of the claimed expenses will occur outside the test year, i.e. between January 1, 1994 and April 30, 1994.

The Department, the RUD-OAG, and MEC contested the inclusion of the four months of expenses occurring in 1994. They characterized inclusion of these costs as a violation of the test year concept that requires matching of test year expenses and test year revenues. They argued that inclusion of out-of-test-year expenses was particularly inappropriate when the Company was using a forecasted test year.

The Company acknowledged that the contested expenses were out-of-test-year and would not normally be allowed. The Company argued for an exception to the general rule, however, on the basis 1) that these costs were known and measurable, 2) that inclusion of the full 12 months of expenses may help avoid a 1994 rate case, and 3) that inclusion would not result in over collection of these costs because the final rates will not go into effect until January 1994.

The Commission finds that NSP's proposal to include these post-test year expenses is contrary to Commission precedent and policy. The Company's request that the Commission adjust the rates upward beginning January 1, 1994 to reflect a full twelve months of Manitoba Hydro expenses is unacceptable for the same reasons. The "known and measurable" exception that the Company relies on is not automatic, as the Company suggests. In a 1988 Order, the Commission stated its reasons for disallowing a test year adjustment for post-test year changes:

> As a general rule, the Commission is reluctant to adjust revenue requirements to reflect changes, certain or not, unless there is a *compelling* reason to do so. (Emphasis added.)[7]

[7] In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota, Docket No. E-015/GR-87-223, ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988), page 3.

The Commission's reluctance is based on the fact that the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical -- some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process.

In this case, the Company has not shown a compelling reason to depart from the normal course. The Company has suggested that allowance of the disputed costs might be adequate to induce the Company to change its announced plans to file another rate case in 1994. However, it is highly unlikely that allowance of the disputed costs would be adequate to change the Company's plans. In short, a suggestion of a chance does not amount to a compelling reason. The Company's final reason is equally unpersuasive. The Company asserted that allowing the additional costs would not result in overrecovery because the rates will not go into effect until 1994. However, the timing of when rates go into effect does not eliminate the test year violation, a mismatch of test year revenue and costs, that would result from approving the Company's proposal.[8]

On the contrary, there are good reasons in addition to Commission precedent to reject the Company's proposal. First, it would be inequitable to adjust for the known and measurable change that would benefit the Company without likewise adjusting for changes that would benefit ratepayers. Since the record does not identify all known and measurable changes to allow such equitable adjustment, the best course will be to maintain the test year boundaries intact. Second, the Company was in full control of the timing of its filing and the selection of the test year period. In light of the Company's control of this issue and the Commission's precedent with respect to test year boundaries, it is reasonable to hold the Company to the consequences of its choices. Finally, it appears that NSP will file another rate case in 1994 and will be able to include the 1994 costs in that case's test year.

Accordingly, the Commission will reduce NSP's test year expense filing by $18,777,000 representing the out-of-test-year Manitoba Hydro expenses. This adjustment increases net income by $9,547,000.

K. Nuclear Decommissioning

NSP included $30.316 million as test year nuclear decommissioning expense in its original filing. This amount was based on the parameters determined in the most-recent triennial

[8] The Commission notes that the possibility of revenue-cost mismatch is heightened when, as in this case, a fully projected test-year is used rather than an historical test-year.

decommissioning review, In the Matter of the Petition of Northern States Power Company for Depreciation Certification for Expected Decommissioning Costs for the Monticello and Prairie Island Nuclear Steam Generating Facilities, E-002/D-90-184, ORDER DETERMINING DECOMMISSIONING COSTS, APPROVING COST RECOVERY PROCEDURES AND ESTABLISHING FUTURE FILING REQUIREMENTS, February 25, 1991. Among other findings that docket established a cost in 1990 dollars of $630 million for the expected cost of decommissioning the nuclear plants in the future, an inflation rate of 6 percent, earnings on tax-qualified external funds of 5.5 percent, and earnings on non-qualified external funds of 7.5 percent. The earnings on the internal fund was established at the Company's authorized after-tax rate of return. NSP indicated that the Commission's decision in the new triennial filing made June 1, 1993 should be incorporated into this filing, if the matter is completed before the order is issued in this docket.

On June 1, 1993, NSP filed its new triennial review of nuclear decommissioning, Docket No. E-002/D-93-504. The executive summary accompanying the filing suggests a proposed decrease in annual decommissioning expense to approximately $20.9 million. On August 2, 1993, NSP filed its request to delay a decision in this matter until after the conclusion of the Minnesota 1994 legislative session. The Company cited uncertainty surrounding the final resolution of the Prairie Island dry-cask project, which is a matter to be taken up at the legislative session. The Commission has requested comments on both the merits of the Company's proposals in the triennial filing and on the request for delay. At this time, the Commission has not acted on either filing.

MEC recommended that the test year decommissioning expense be reduced by approximately $20 million to reflect decreased costs. Alternatively, MEC recommended that the test year decommissioning expense be reduced by approximately $9.4 million to reflect the amount proposed by NSP in the new triennial filing, and that the Commission should establish a true-up mechanism to assure that NSP does not earn a windfall profit if the rates are set in this rate case based on a higher decommissioning expense than is ultimately determined in the new triennial docket. At oral argument, MEC emphasized its major concern to be that of preventing a windfall from flowing to NSP's shareholders as a result of a higher test year expense than is likely to be allowed in the new triennial docket.

The Department initially recommended that rates established in this docket reflect the decision in the new triennial review, if possible. At oral argument, the Department stated that it would prefer that no change be made to the decommissioning expense included in this rate case and that the decision in the new triennial review be deferred until the legislature addresses the dry-cask issue. Alternatively, the Department recommended that if a change is made to the expense included in the test year, that it reflect the new triennial amounts starting August 1, 1993.

The ALJ recommended the rejection of MEC's proposal to decrease test year decommissioning expense by $20 million for changed financial parameters. The ALJ did recommend that the test year decommissioning be reduced by $6.4 million. The ALJ determined that amount by taking official notice of the new triennial filing, implementing the proposed lower expense effective August 1, 1993, and reducing the test year expense by approximately one-half of the difference between the expense calculated in the old triennial filing and the new triennial filing for the first seven months of the test year. The ALJ stated that the purpose of the adjustment was to avoid the potential for a windfall to the Company, should the decommissioning cost later be determined to be less than the amount included in the test year.

The Commission will reject MEC's proposal to reduce test year decommissioning expense by $20 million. In calculating that adjustment, MEC focused on limited provisions of the Energy Policy Act of 1992 which eliminate the lower yielding "Black Lung" investments requirement to achieve tax qualified status and reduce the tax rate to 22 percent from 34 percent beginning in 1994.

The Commission finds that it is not appropriate to assume that, because the external tax-qualified funds are no longer limited to lower-yielding investments under the "Black Lung" restrictions, the earnings on the tax-qualified fund will automatically increase from 5.5 percent to the 7.5 percent rate on the non-qualified funds. The Commission accepts the arguments made by NSP that the investment portfolio for the tax-qualified fund was limited to lower-risk and lower-yielding securities, while the non-qualified fund was made up of higher-risk, higher-yielding securities. It is inappropriate to simply assume all investments are in the higher-risk, higher-yielding securities. An analysis to achieve a properly balanced portfolio is necessary, an issue which has not been addressed by MEC here and which is frequently a matter of review in the triennial filing dockets.

MEC recommended that lower tax rates be incorporated into the calculations, decreasing test year expense by increasing net earnings on the investments. NSP criticized MEC's calculations, arguing that MEC applied the lower rates to the non-qualified funds as well as the tax-qualified funds, contrary to the provisions of the Energy Policy Act of 1992. MEC did not update its schedules to reflect this correction. The Commission finds the tax rate issue on decommissioning funds to be the type of issue which would receive specific review in the triennial filing, eliminating any remaining uncertainty.

MEC recommended that the inflation rate be decreased based on an urban inflation index. The Commission notes that the inflation rate was determined using a nuclear specific inflation analysis in the 90-184 triennial review. MEC has not made an effort to quantify a comparable inflation rate. The Commission rejects the recommended adjustment to the inflation rate. Again MEC has not presented comparable data. MEC's recommendation is also contradictory in that it advocates a position of higher earnings on investments while advocating a decrease in inflation rates.

In summary, the Commission rejects MEC's recommendation to reduce test year decommissioning expense by $20 million. MEC has addressed only a few of the components of the decommissioning expense equation. There is no evidence that MEC has conducted a new study of the costs to decommission, conducted a current analysis of investment conditions, or conducted a current analysis of the preferred investment mix absent the "Black Lung" restrictions. NSP's rate filing includes decommissioning expense based on the last full decommissioning review conducted in docket 90-184. To modify only a few of the components without consideration of all the components results in a very fragmented analysis. Such fragmented analysis is best avoided by considering all components simultaneously in the triennial dockets.

The Commission will take official notice of the fact that NSP made a new triennial filing made on June 1, 1993. However, the Commission will not adjust the filed test year decommissioning expense to reflect the amounts contained therein. While NSP proposed an expense decrease in the new triennial filing, absent a full review, the proposals and data included in the new filing are simply raw data which cannot be relied upon for rate setting purposes. Further, it is possible that it may be necessary to increase decommissioning expense depending on the direction received from the upcoming legislative session. Due to the raw data, coupled with the additional uncertainties surrounding the Prairie Island dry-cask storage issue before the legislature, the Commission will not adjust test year decommissioning expense in this case. A decrease now could potentially be offset with an increase in the near future, contributing nothing to rate stability.

However, the Commission joins in the concerns expressed by MEC and the ALJ about the potential for a windfall for shareholders. If circumstances develop in the future that justify a decrease in annual decommissioning expense, it is likely to occur sometime after the completion of this rate case. At that time, rates will be set, with little opportunity to make adjustments. The Company suggested that if the costs included in the test year decrease at a later date, normal ratemaking practice would permit the excess funds to be applied to other costs, or flow to retained earnings. However, the Commission finds that this issue is not a normal ratemaking issue. The Company has not yet incurred decommissioning costs and will not incur them until after the shutdown of the nuclear units; ratepayers are supplying funds in advance of the expenditures by the Company. Costs are included in rates for the purpose of matching the expected future decommissioning costs with the service provided and for the purpose of accumulating funds to meet the future costs.

Other than adjusting the expense for the rate of return finally determined in this proceeding, the Commission will not adjust the Company's proposed test year decommissioning expense. At the same time, however, no windfall will be allowed; no amounts overcollected will be applied to offset other costs or flow to retained earnings. Due to the unique character of the expense and the uncertainties discussed above, the Commission will require the Company to deposit the amounts collected in rates for decommissioning resulting from this proceeding in the proper funds, thereby maintaining the amounts collected in a manner in which ratepayers will receive benefit of the full amounts in future decommissioning proceedings. This concern (prevention of windfall) shall also be considered when the new triennial filing is decided.

L. Social Expense

NSP included $391,000 as social expense for the test year. NSP indicated that these costs were disallowed in its last rate case, E-002/GR-91-1, due to auditability and corporate policy concerns. NSP cited the November 27, 1991 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at page 40 where the Commission indicated that "social expenses are indeed part of an appropriate DOE budget" but "they must be open to meaningful review in order to be included as rate case expenses." NSP indicated that it has now provided for the auditability of the costs and has established a limit of $75 per employee which has not been exceeded on an overall basis. NSP argued that no adjustment is now appropriate. These costs are necessary to promote employee morale, teamwork, and efficiency.

The Department indicated that it reviewed the social expenses as part of its on-site audit. The Department recommended that no adjustment was necessary, indicating that the costs are now auditable and that NSP has established a corporate policy, including a $75 per employee limit, to achieve control of the costs.

The RUD-OAG recommended that the full amount be excluded from rates. The RUD-OAG argued that NSP did not show the costs are necessary in the provision of service. Simply making the costs auditable and having a policy does not assure they are necessary for the provision of service. Also, NSP did not show how ratepayers benefit by allowing retired employees to participate in the $75 limit.

The ALJ recommended that the social expenses be allowed for rates. The ALJ referenced the Commission's Order in E-002/GR-91-1 where the costs were found appropriate but that they must be open for review. The ALJ also found the costs necessary and reasonable in utility cost of service and that it is within the purview of management discretion to allow for a reasonable level of employee social expenses to promote a favorable work environment, enhancing efficiency and teamwork.

The Commission accepts the recommendation of the ALJ. Based on the on-site audit conducted by the Department and its recommendation, the Commission is satisfied that the costs are reasonable and necessary in the provision of electric service. Further, the Commission is satisfied that the inadequacies found in the last case have been resolved.

M. Sunnybrook Farm

The Sunnybrook Farm issue involves potential liability to NSP for possible contamination resulting from used oil provided by NSP for use on the farm. NSP argued that because it is still pursuing clean-up costs and insurance recovery litigation, and because the Company included no costs or revenue for this matter in this rate case, that it is not appropriate to make a decision at this time.

The RUD-OAG originally recommended that $210,849 of insurance recoveries be included in rates. In proposed findings, the RUD-OAG recommended that no adjustment be made at this time.

The ALJ recommended that no adjustment be made at this time. The ALJ found that the record does not contain sufficient information on whether the costs are or are not a proper ratepayer expense. The ALJ described the matter as premature.

The Commission will not make an adjustment for the insurance recovery in this rate case.

N. Taxes

NSP proposed to include the effects of four pre-test year tax issues in the test year. Initially, the Company included approximately $3 million as an increase to test year net income. In rebuttal, the Company agreed that it would be appropriate to amortize the amount over two years, with the unamortized balance included as a reduction to rate base. Adjusting the original filing to reflect the amortization reduces test year net income by $1,484,000, and reduces test year rate base by $1,763,000.

NSP indicated that the four tax items arose due to audits and disputes with the IRS. Those disputes were finally disposed of in 1991 and included:

1. Spare Parts: This matter arose due a change in accounting for spare parts in 1989, leading to a refund to ratepayers. The tax rate at the time a tax refund was sought from the IRS was 34 percent, but the tax rate was 46 percent when the taxes were originally paid. NSP sought the tax refund based on the 46 percent rate and received authority from the IRS to do so in 1991.

NSP proposed to include the tax credit of $2.27 million for rate purposes.

2. DOE Charge: The DOE reduced the spent fuel charge related to fees collected from 1983 to 1991. The fee reduction will be refunded through the automatic fuel adjustment clause. The Company succeeded in receiving the related tax refund based on a 46 percent rate instead of the 34 percent rate.

NSP proposed to include the tax credit of $168,000 for rate purposes.

3. Research Tax Credit: The Company invested in research and development (R&D) projects at the Blackdog facility. The Company succeeded in gaining tax treatment under special R&D tax rules.

NSP proposed to include the tax credit of $1.4 million for rate purposes.

4. Interest: The IRS successfully challenged various tax interpretations made by NSP in the years 1984, 1985, and 1986.

NSP proposed to include the resultant interest charge of $1.5 million for rate purposes.

NSP also sought that the Commission establish a form of tax tracker which would allow the Company to defer debits and credits at the time tax disputes involving matters affecting utility operations are resolved. The deferred balance would then be included in a subsequent rate proceeding.

The Department recommended that the tax credits be allowed for rate purposes, but that the interest cost be excluded from the test year. Regarding the tax credits, ratepayers paid the taxes through rates and are entitled to the refunds. Regarding the interest expense, it is outside the test year and deferred accounting has not been sought by the Company in a timely manner.

The Department argued that there was no need for a tax tracker policy; the Commission already has a policy in place. That policy requires that the utility must file a petition for deferred accounting before attempting to defer an expense to later periods, as detailed in Minnegasco 91-1015. The policy also provides that the Commission can and will consider revenues in subsequent rate cases without a petition for deferred accounting, as detailed in NSP 92-371.

The ALJ recommended allowing the tax credits and disallowing the interest expense. NSP failed to file a timely petition seeking deferred treatment for the interest expense, and the cost was not incurred in the test year. The tax credits should be allowed because they are refunds of taxes previously included in rates, and this is the first opportunity to transfer the refund to ratepayers. The ALJ recommended no tax tracker since the Commission already has a policy.

The Commission will permit the inclusion of both the tax credits and the interest expense in the test year, amortized over two years with the unamortized balance included in rate base. Inclusion of the full amount in the test year could lead to excess benefits being distributed to ratepayers if the Company does not file for a rate case within one year. A two-year amortization more appropriately reflects NSP's recent rate filing history.

In this case, NSP requested treatment similar to that approved by the Commission in NSP's prior rate cases, Docket Nos. E-002/GR-81-342 and E-002/GR-85-558. In light of this history, NSP had a reasonable expectation that the Commission would approve this treatment in this case. In this instance, therefore, the Commission will include both the tax credits and interest expense in the test year. It appears NSP waives any argument that such treatment is retroactive ratemaking. Therefore, the Commission will not address that issue. In the future, however, the Commission will expect NSP to seek and receive approval from the Commission prior to recording such expenses in a deferred account.

This treatment of taxes is also consistent with sound public policy. The facts at issue here involve income taxes. Income tax laws are subject to a great deal of interpretation. Interpretations of tax laws are frequently challenged by the IRS. The challenges may lead to protracted litigation. Here the record indicates that the disputed items finally resolved apply to periods as early as 1984. Also, the record clearly shows that there may be substantial benefits through lower tax bills if the utility maintains an aggressive posture when interpreting tax laws.

Typically, a utility will estimate costs for a test year, parties have a process available to review those estimates, and rates are ultimately set. If the circumstances change, causing expenses to deviate significantly from the estimates used for rate setting, either the utility could seek a rate change or a rate change proceeding could be initiated by the Commission. However, with the tax disputes, significant changes in estimates may only be realized a number of years later, too late to initiate a rate change to correct for the change in circumstances in a timely manner. This leads to a higher degree of risk faced by the utility, especially if the utility takes an aggressive posture in interpreting tax laws, a posture which may lead to decreased costs for ratepayers. Thus it is appropriate for the Company to seek deferred accounting treatment for disputed tax items.

While aggressive tax interpretations may lead to lower taxes included in rates, the risk of losing before the IRS serves as a disincentive to maintaining an aggressive posture. By allowing the inclusion of the tax credits, as well as the interest expense, this disincentive is removed. Ratepayers receive the benefits of decreased taxes, while still paying their proper share.

Regarding the request for a policy on a tax tracker, the Commission will not establish an automatic procedure. Because rate proceedings already are large and complex undertakings, the Commission will not permit the automatic accumulation of tax matters for review in subsequent rate cases. To maintain an element of control over the items deferred, the Commission will require that the Company petition for deferred accounting status of both tax credits and debits at the time the final decisions are received on the disputed items. Items for which deferred status is sought should be limited to significant and unusual disputed items related to utility operations, for which ratepayers have incurred costs or received benefits.

O. Purchasing and Contracting

The purchasing and contracting issue was also raised in the concurrent NSP Gas case, Docket 92-1186. Although raised in both cases, this issue was not addressed as a common issue.

The Department conducted a review of NSP's purchasing and contracting practices. The review was focused on O & M expense items, excluding fuel and purchased power, and was based on samples drawn from various accounts. As a result of its review, the Department raised concerns that the Company rarely seeks competitive bids for goods and services, and when bids are taken, the Company rarely takes the low bidder, or even the second lowest bidder. The Department recommended a reduction in test year tree-trimming expense of $522,000, representing approximately 50 percent of the high bid percentage. The Department also recommended that the Company file a report on its contracting and purchasing activities within three months of the date of this order. That report would demonstrate the steps that NSP takes to minimize contract-related costs, consistent with the need to obtain high-quality and reliable service. The report would also explain the criteria used to evaluate competitive bids.

NSP opposed any adjustment to the test year tree-trimming expense, and opposed any further filings of information. NSP argued that the test year costs are reasonable and appropriate. Further, NSP indicated that it has already supplied copies of its Purchasing Department Policy and Procedure Manual and its Index of Guides for Power Supply Purchasing to the Department. The Department has cited no deficiencies in those manuals.

The ALJ recommended the reduction of test year expense by $522,000 and the filing of a report within three months as described by the Department.

The Commission will not reduce test year tree-trimming expense, and will direct that the Department first file a report on NSP's current purchasing policies and procedures before requiring further filings from the Company.

The Department calculated an adjustment based on tree-trimming expense. That adjustment was based on a 50 percent disallowance of the difference between the low bids and the bids accepted. The Department indicated that a 50 percent disallowance would allow for the possibility that NSP sometimes selected high bidders for reasons other than inefficiency, poor contracting or bad business judgment. The Commission finds the proposed adjustment represents a form of "across-the-board" adjustment. Instead of finding that specific individual costs are excessive or unreasonable for the test year, the argument is made that because there may be something wrong with the procedures a portion of an entire category of costs should be disallowed, as if by proxy. The Commission has consistently refused across-the-board or benchmark adjustments, instead preferring to focus on specific individual items of costs. See Minnesota Power and Light, Docket No. E-015/GR-87-223, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (March 1, 1988) at page 35. The Commission is not persuaded that an across-the-board adjustment is warranted here, and will instead look to the individual arguments in an attempt to determine if there is evidence of excessive test year costs.[9]

NSP made copies of its purchasing manuals available to the Department. However, the record shows that the Department performed no analysis of the procedures and did not perform a compliance review. The Department expressed concern that NSP did not seek bids for cleaning services at NSP's Dodge Center facility, yet the record shows there were no other providers in the area. The Department expressed concern that some repair parts for a Spectrometer were not competitively purchased, yet the record shows they were purchased from the supplier of the Spectrometer itself. The discussion in the record suggests that the Spectrometer is a specialized piece of equipment with limited availability of competing parts providers. On these items the Department made no recommendation for a test year expense adjustment.

Addressing the tree-trimming costs, the Department based its recommendations largely on the results of bids taken in 1988. The Department could not quantify the amount that test year costs were excessive due to the bids accepted in 1988. Instead, proprietary exhibit 148 indicates that the price advantage of the low bidder in 1988 has largely disappeared in the test year.

The Commission finds it is not appropriate to judge the reasonableness of the costs based solely on "low bid" criteria. Customer satisfaction, safety, dependable operations, equipment, and experienced personnel are all necessary considerations.

---

[9] The policy against across-the-board adjustments applies to utility costs in general, but not to economic development costs which receive special statutory treatment. In deciding the extent to which such expenses will be allowed, the Commission may use its sound discretion, which includes applying an across-the-board adjustment. Minn. Stat. § 216B.16, subd. 13 (1992). See page 49 in this Order.

Disgruntled customers, injuries, and the risk of excessive litigation must also be considered in evaluating which bidder should be selected.

Based on its analysis of the record, the Commission concludes that the Company has based its selection of tree-trimming contractors after due consideration of all necessary factors. The Commission, therefore, finds that its tree-trimming expenditures are reasonable and will allow them.

Nevertheless, the Commission is concerned that ongoing practices of the utilities under its jurisdiction lead to reasonable costs and services. Instead of directing the Company to file further reports and studies at this time, however, the Commission will direct the Department to conduct an analysis of NSP's purchasing practices beginning with the manuals already supplied to it by NSP. The Department should report on the policies, procedures, and compliance within six months of the order in this docket.

P. Sales Forecast and Billing Determinants

1. Description of NSP's Forecasting Process

Using a combination of forecasting techniques, NSP forecasts sales to seven customer classes: Residential with Electric Space Heating; Residential without Electric Space Heating; Small Commercial & Industrial; Large Commercial & Industrial; Other Sales to Public Authorities; Public Street & Highway Lighting; and Interdepartmental Sales. NSP obtains monthly customer counts from its Operating Regions. For the first four customer classes in the list above, which collectively account for about 99 percent of the Company's retail electric sales, NSP uses econometric models to derive quarterly sales estimates. NSP uses different econometric equations for each of these classes. NSP reduces the econometric results by a small "conservation adjustment" to reflect conservation program growth not captured in the historical data. To project sales to the remaining classes, NSP's Operating Regions use a combination of historical trends, customer growth information, and judgment. NSP obtains the forecast total by summing the results for the various classes.

Using the methodology described above, NSP produces adjusted sales levels on a "revenue month" basis for each quarter. For purposes of projecting test year revenues, the Company makes an adjustment by class for unbilled sales to reflect sales on a "calendar month" basis.

In order to provide sales and revenues by service schedule, NSP also has to produce monthly sales data. The Company disaggregates the quarterly projections discussed above for the four major classes into monthly data, using two different techniques. In order to estimate billing data for each month of the test year, the Company uses sales and customer data to develop growth rates which are then applied to the more detailed historical billing data for each rate schedule. NSP applies the present rate levels to the resulting projected year billing data to determine present revenues by rate schedule. The sum across rate schedules provides test year sales revenues under present rates.

NSP calculates matching production expenses using a computer simulation which schedules the generating units and power purchases in order of increasing operating costs. The Company estimates fuel prices using fuel contracts and other known information.

2. Sequence of Forecasts/Filings in This Rate Case

The results of NSP's initial forecast were included in the Company's rate case filing. For the seven groups of customers listed above, NSP projected total sales of 24,796,985 megawatt-hours (MWh). The corresponding retail revenues for these sales under present rates were $1,318,876,000. (This revenue total does not include revenues from Interdepartmental Sales, which were included in the category "other revenues" in the financial schedules. There was no dispute about those revenues in this rate case.) To reflect unbilled sales, the Company added $4,775,000 to present revenues. NSP listed total production expenses of $634,386,000.

In its direct testimony, the Department provided a critique of the Company's forecast. The Department also included a description of the techniques and results of its own forecast. In its testimony, the Department accepted NSP's projected numbers of customers and also NSP's projections for Other Sales to Public Authorities, Public Street & Highway Lighting, and Interdepartmental Sales. The Department developed econometric models for the four major customer groups. The Department, for the most part, used the same underlying data sets as the Company. However, the Department excluded or replaced data series found to be inaccurate. The Department's initial forecast indicated total projected sales of 25,081,674 MWh, about 1.15 percent higher than the projection of the Company. Using the results of its forecast, the Department recommended increases in NSP's filed retail revenues and production expenses of $16,359,000 and $4,587,000, respectively. The Department accepted NSP's figures for unbilled sales and unbilled revenues.

In its rebuttal testimony, NSP agreed there had been errors in the data series for the cooling and the marginal price variables used by the Company in its initial forecast. The Company corrected those data errors and respecified its models using the corrected data series. The Company's revised forecast produced an increase in retail sales to 25,013,423 MWh and a $12,946,000 increase in projected retail revenues to $1,331,822,000. The corresponding increases in unbilled revenues and production expenses, as compared to the amounts originally filed, were $77,000 and $3,482,000, respectively. NSP also indicated that it had found a minor error (i.e., a miscalculation in the adjustment for test year fourth-quarter billing cycle days) in the data used in the Department's initial forecast.

In its surrebuttal testimony, the Department also submitted a revised forecast. To produce that forecast, the Department substituted NSP's corrected weather series for the corresponding weather series initially used by the Department, removed an adjustment for serial correlation in the Residential without Electric Space Heating model, and corrected the data error pointed out by the Company. The Department's revised forecast indicated total sales of 25,062,853 MWh. The resulting increases from NSP's original positions on retail sales revenues and production expenses were $15,584,000 and $4,273,000, respectively.

3. NSP's Offer of Proof

In the hearings and in its briefs, NSP argued that a comparison of projected sales with actual sales should be admitted into the record. NSP argued that the time period in question (i.e., 4th quarter 1992 and 1st quarter 1993) is now over. According to the Company, the existence of actual results renders theoretical discussions moot. NSP argued that the information shows that the Company's revised forecast is more reliable and accurate than that of the Department. NSP indicated that the Department had time to review those results but instead opposed the entry of the information into the record.

After receiving comments from the parties, the ALJ did not allow the indicated comparisons into the record. In his Report, the ALJ reaffirmed his prior ruling on exclusion of the information from the record, stating that the 10-month statutory deadline requires a cutoff of updates and other evidence at some point in the process.

The Commission agrees with the ruling of the ALJ. The prefiling deadlines in this docket provided for three rounds of testimony before the start of the hearings. Normally, the filing of direct, rebuttal and surrebuttal testimony should provide sufficient opportunity for parties to present their positions to the ALJ and the Commission. It would have been difficult to accommodate significant new testimony at the hearing because of the time that would have required. New testimony could not reasonably have been allowed into the record without giving the other parties time to study the new information and react to it. The Commission will not consider the information from NSP's offer of proof in selecting a forecast for use in deciding this rate case.

4. The Department's Offer of Proof

At the hearing, the ALJ excluded from the record several criticisms by the Department of NSP's revised forecast. The ALJ sustained NSP's objection that the evaluative comments went beyond the scope of the cross-examination and therefore constituted improper redirect examination. The ALJ allowed the Department to make an offer of proof, should the Commission decide to consider the evaluative comments. In its post-hearing briefs, the Department renewed its request to have the information added to the record. The ALJ reaffirmed his prior ruling on the Department commentary in his Report, citing the need to cut off updates and other new information to permit a timely final Order in this docket.

The Commission accepts the evidentiary ruling of the ALJ. As with NSP's offer of proof, it would be difficult for the Commission to put much weight on the excluded information, since it could not be tested by other parties or the Commission. Further, the Commission believes that the circumstances surrounding the two offers of proof are sufficiently similar to require equal treatment of the two parties. The Commission will not consider the information from the Department's offer of proof in selecting a forecast for use in deciding this rate case.

5. Position of the Company on the Sales Forecasts

NSP stated that its objective in providing a corrected forecast was to provide the Commission with the most accurate and useful information possible. The Company argued that its revised forecast is a more reliable and accurate predictor of test year sales than the Department's revised forecast. NSP's revised forecast increases net income by $5,680,000.

NSP argued that its witness Dr. Campbell had explained at the hearing the necessity of the changes that were made by the Company in producing the revised forecast. Upon correcting the data series, Dr. Campbell reviewed control statistics on the variables in each model to determine whether a revision of the model was necessary. According to the Company, failure to make the indicated changes would have resulted in a biased forecast.

NSP also disagreed with the Department's contention (discussed below) that it lacked time for verification of the revised NSP models. According to the Company, by the time of rebuttal testimony the Department had already done most of the required work in learning the data series, the adjustments, the variables, and the models. The Company argued that the Department could have known by March 24 that it did not have all of the specific models for the Company's revised forecast and that a data request was appropriate. According to the Company, the Department had sufficient time to verify NSP's revised forecast had it chosen to use that time.

The Company also criticized the revised forecast of the Department. According to the Company, the Department's forecast relied on model specifications that were created using an incorrect cooling degree day data series, the coefficient for the heating variable in the Large Industrial model had the wrong sign, the Large Industrial model had too low a price elasticity, and the forecast relied too heavily on correction for autocorrelation of residuals. The Company acknowledged that the Department had made some appropriate changes but argued that it did not pursue the most essential one--respecification of the models.

6. Position of the Department on the Sales Forecasts

The Department urged the Commission to adopt the Department's revised forecast, stating that its forecast is more reasonable and better supported than the Company's revised forecast.

The Department indicated that its revised forecast avoided the erroneous data points and biased variables that NSP relied upon in preparing its original forecast. The Department argued that its process maintained the integrity of the forecasting process in the regulatory setting by using data and models that had ample examination and by using only simple and reasonable improvements without adding and/or deleting variables and respecifying all of its econometric models. The Department indicated that its goal throughout the hearing process was to produce a reasonable and accurate forecast based on the conditions presented by NSP in its original filing.

The Department stated that its revised forecast reflected only three modifications which NSP's witness had described as reasonable. According to the Department, NSP assumed that with correction of the minor data error the Department's forecast would move downward by 56.4 gigawatt-hours (GWh) and be only 11.9 GWh higher than NSP's revised forecast. When the Department incorporated all three changes, the revised forecast differed from NSP's rebuttal forecast by 48.9 GWh. The Department indicated that NSP then decided to modify Dr. Campbell's testimony and tack on a new, insignificant, and unsupported criticism of the Department's forecast (i.e., that the Large Industrial model "has a wrong sign and too low a price elasticity").

The Department argued that it had insufficient time to verify NSP's revised forecast. According to the Department, NSP's revised forecast is truly a whole new forecast in that every econometric model was respecified. Variables were added and dropped and different data sets were used. When NSP submitted its revised forecast in its rebuttal testimony, the Department had less than two weeks to attempt to replicate, verify and respond in its surrebuttal testimony. The Department indicated that it did not receive all of the documentation needed to verify NSP's revised forecast until April 8, one day after the hearing started.

7. Recommendation of the ALJ and the Commission's Decision

The ALJ indicated that the two revised forecasts are only about 49 GWh apart, a difference of about 0.2 percent. (Accepting the Department's revised forecast rather than NSP's revised forecast would reduce the revenue deficiency by approximately $1,770,000, other things being equal.)

The ALJ selected NSP's revised forecast as likely to be the more accurate. He stated that selecting a forecast as more accurate "is difficult because of the relatively obscure nature of the differences between the two forecasts." He went on to state that none of the differences discussed by the parties "appears to be so substantial that it clearly forces the decision one way or the other." As a result, he compared the credentials and experience of the two forecasters. He cited NSP witness Campbell's credentials and experience, as well as his ability to explain and defend his forecast, as reasons to adopt NSP's revised forecast. He also accepted NSP's argument that models should be respecified when significant changes are made in the data set.

The ALJ concluded that it is appropriate to set test year sales at 25,013,423 MWh. Therefore, he recommended no change to NSP's rebuttal income statement as a result of the forecasting issue.

The Commission agrees with the ALJ that selection of a forecast in this case is extremely difficult because of the obscure nature of the differences between the forecasts. However, the Commission is persuaded that the Company was correct in asserting that the data changes were sufficiently significant to require respecification of the forecasting models. Therefore, the Commission agrees with the ALJ that the Company's revised forecast should be used in deciding this rate case.

In making this decision, the Commission does not rely to any great extent on the comparison of the credentials and experience levels of the two forecasters. The Commission agrees with the Department that the forecasting decision should rest on the comparative merits of each party's forecast.

Forecast accuracy is of primary importance in determining present revenues for the test year. Since NSP's forecast is based on respecification of the forecasting models, the Commission concludes that NSP's revised forecast is the most accurate forecast submitted in this proceeding.

Q. Interest Synchronization

NSP included an income tax deduction for interest expense of $85,100,000 in its original filing. The Company calculated the interest expense using the concept of interest synchronization, in which the rate base is multiplied by the weighted cost of debt. No party objected to this method. The RUD-OAG and the Department included similar calculations in their recommendations. The ALJ recommended that adjustments were necessary. The Commission finds that this treatment is consistent with prior Commission decisions affecting NSP and will incorporate this treatment here.

The Commission will adjust the interest deduction to $78,320,000 to incorporate the rate base and debt cost adjustments by the Commission, including the cash working capital effect of the increase awarded. This adjustment increases income tax expense and decreases test year net income by $2,743,000.

R. Wind Turbine Project

As discussed in part E of the rate base section of this order, the Commission removed the Wind Turbine Project from the test year rate base. The Commission also will remove the wind turbine project from the income statement, reducing test year net income by $645,000, largely to reflect AFUDC and tax effects.

S. Depreciation Study

As discussed in the Depreciation Study part of the Rate Base section of this Order, the Commission incorporated the most recently approved depreciation rates and methods. Incorporation of the depreciation rates reflecting the 1993 annual study and the 1993 five-year study reduce test year net income by $2,218,000. Incorporating the change in depreciation methods for the interim storage facility at Prairie Island increases test year net income by $13,000.

T. Updates to Filing

As discussed in the Rate Base section of this order, the Commission accepted certain modifications proposed by NSP in two updates to its original filing. The related Operating Income Statement effects will be identified below.

1. February 17, 1993 Update

a. MPCA Fee

In its update, the Company corrected its calculation of MPCA emission fees for the test year. This correction increases test year net income by $103,000.

No party opposed this adjustment. The ALJ incorporated the adjustment without comment. The Commission accepts this correction as appropriate. There is no related rate base effect.

b. United Hospital

The related Operating Income Statement effect of the correction in the contribution in aid of construction, as discussed in the Rate Base section of this order increases net income by $2,000.

c. Fuel Handling and Inventory

The related Operating Income Statement effect of the modification in fuel inventory, as discussed in the Rate Base section of this order, decreases net income by $157,000.

2. February 19, 1993 Update

This update largely reflected adjustments to the original filing due to proposed changes to the capital structure and cost of capital. The Commission will detail the uncontested adjustments for AFUDC, nuclear decommissioning, end-of-life nuclear fuel, coal mine reclamation, interchange, and the adjustments reflecting the finally authorized cost of capital. Effects related to conservation and interest synchronization will be included in the respective sections elsewhere in this order.

a. AFUDC

As discussed in the Rate Base section of this order, the Commission accepted adjustments to the test year AFUDC. This adjustment reduces test year net income by $1,824,000.

b. Nuclear Decommissioning

As discussed in the Rate Base section of this order, the Commission adjusted the test year nuclear decommissioning expense to reflect the rate of return awarded by the Commission in this proceeding. This adjustment reduces net income by $1,086,000.

c. End-of-Life Nuclear Fuel

NSP maintains an internal sinking fund which accumulates funds to recover the remaining value of nuclear fuel contained within the reactors at the expiration of operations. The related accrual depends on the rate of return awarded. The Company proposed to modify test year expense to reflect the rate of return finally awarded.

No party opposed the adjustment. The ALJ incorporated the adjustment without comment.

The Commission will adjust the original filing to incorporate end-of-life fuel calculations based on the rate of return finally awarded in this proceeding. This adjustment reduces test year net income by $132,000. There is no related rate base effect.

d. Coal Mine Reclamation

NSP proposed to recover the final reclamation costs of the Westmoreland Mine through a sinking fund method based on the rate of return authorized.

No party opposed the Company's proposal. The ALJ did not address the proposal.

The Commission will adjust test year expense to reflect the rate of return finally awarded. This adjustment reduces test year net income by $4,000. There is no related rate base effect.

e. Capital Structure, Interchange Agreement

The Company included an adjustment to the test year income statement reflecting the effect of the modified cost of capital and capital structure on interchange agreement revenues and expense.

No party opposed this adjustment. The Commission will accept the adjustment, reducing test year net income by $10,000. There is no related rate base effect.

U. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is $183,203,000 as shown below (000's omitted):

Operating Revenues:	
Retail Revenues	$1,331,832
Unbilled Revenues	4,852
Other Operating Revenues	162,466
Gross Earnings Taxes	23,345
Total Operating Revenues	$1,522,495
Operating Expenses:	
Production	$ 619,231
Transmission	33,155
Distribution	73,078
Customer Accounts	28,477
Customer Information	10,407
Administrative and General	132,598
CIP/DSM Amortization	21,172
Other Expense	3,788
Depreciation and Amortization	187,303
Taxes:	
Real Estate and Property	130,561
Gross Earnings	23,345
State and Federal Income	84,043
Deferred Income	(17,897)
Other	16,436
Total Operating Expenses	$1,345,697
Operating Income Before AFUDC	$ 176,798
AFUDC	6,405
Operating Income With AFUDC	$ 183,203

XIII. RATE OF RETURN

A. Introduction

The overall rate of return represents the percentage the utility is authorized to earn on its Minnesota jurisdictional rate base. The overall rate of return is determined by the capital structure, which is the relative mix of debt and equity financing most of the rate base, and the costs of these sources of capital. The Commission will first address the capital structure, then the costs of debt and preferred stock and the cost of equity. Finally, the Commission will put these factors together to derive the authorized overall rate of return on rate base.

Four parties submitted rate of return testimony in this proceeding. Mr. Paul E. Pender testified for NSP, Dr. Luther C. Thompson for the Department, Mr. Matthew I. Kahal for RUD-OAG, and Mr. Peter Ahn for MEC.

B. Capital Structure

1. Summary of the Parties' Positions

After a number of updates to account for errors and changing financial conditions, NSP proposed a capital structure consisting of 38.80 percent long-term debt, 4.56 percent short-term debt, 8.26 percent preferred stock and 48.39 percent common equity as shown below:

Capital Employed	Amount (Thousands)	Percent
Long-Term Debt	$1,294,312	38.80
Short-Term Debt	151,996	4.56
Total Debt	$1,446,308	43.36
Preferred Equity	$ 275,493	8.26
Common Equity	$1,614,259	48.39
Total Capital	$3,336,060	100.00

The percentages are based on the forecast capitalization for the test year ending December 31, 1993.

After comparing the Company's proposed equity ratio with that of comparable companies, the Department witness supported NSP's proposed capital structure as being reasonable. Dr. Thompson recommended that the Commission continue to closely monitor NSP's rising equity ratio and put the Company on notice that equity ratios beyond the average ratios of companies of comparable risk may not be allowed for regulatory purposes in future cases. The RUD-OAG witness, Mr. Kahal, noted that NSP's proposed capital structure is typical of a strong AA-rated utility, and did not believe the Company's projections were unreasonable.

2. Recommendation of the ALJ

The ALJ found that NSP's proposed capital structure, which included a common equity ratio of 48.39 percent, was reasonable. He noted that the Company's equity ratio showed a trend similar to the equity ratios for comparable electric and gas companies.

3. Commission Findings and Conclusions

The Commission is charged with determining the most reasonable capital structure for NSP for ratemaking purposes. In making this determination, the Commission finds that the relative proportions of the various forms of capital employed by the Company must be reviewed to ensure that ratepayers are not being required to pay an unnecessarily high cost of capital. The equity ratio is of particular concern. Because common equity is typically the highest cost capital, use of too much common equity in the capital structure could cause an excessive cost of capital. Conversely, a low common equity ratio could increase the risk that earnings will not be sufficient to pay fixed-cost obligations, causing other financing costs to rise.

The Commission must, therefore, be satisfied that the Company has established a capital structure that properly balances the needs of ratepayers for economy and the needs of investors for safety. If the Commission finds that the Company has not achieved a reasonable balance, the Commission will adjust the capital structure for ratemaking purposes to put it within a reasonable range.

The Commission finds that based upon the comparable group evidence in the record, the capital structure proposed by NSP is reasonable. Mr. Pender submitted evidence demonstrating that equity ratios for comparable AA-rated utilities averaged 50.48 percent at year-end 1991. Dr. Thompson found average equity ratios of 50.40 percent for his gas comparable group and 46.26 percent for his electric comparable group. NSP's proposed equity ratio compares favorably with the equity ratios of utilities of comparable risk, and appropriately balances the competing interests of investors and consumers.

In adopting NSP's actual capital structure for the test year, the Commission is not specifically endorsing NSP's stated financial goals, nor is it advocating the use of a utility's actual capital structure for ratemaking as appropriate in all cases. The Commission continues to reserve its authority to examine a utility's capital structure and adjust it for ratemaking purposes where deemed necessary. NSP will be required to justify its proposed capital structure in future rate proceedings, and the Commission may adjust that capital structure if it finds that the Company's equity ratio is unreasonable for ratemaking purposes.

C. Costs of Long- and Short-term Debt and Preferred Stock

In its original filing, NSP proposed a test year cost of long-term debt of 8.49 percent, short-term debt of 5.92 percent, and preferred stock of 5.75 percent. In its rebuttal testimony, it updated its cost of long-term debt to 8.49 percent, its short-term debt to 4.65 percent, and its preferred stock to 5.57 percent. Later, in response to an OAG information request, NSP further revised its long-term debt cost to 8.05 percent.

No party challenged NSP's cost of preferred stock. RUD-OAG witness Matthew Kahal challenged NSP's estimates of long- and short-term debt. In his surrebuttal testimony, Mr. Kahal argued that NSP's cost of long-term debt should be 7.76 percent and its cost of short-term debt should be 4.0 percent.

Mr. Kahal based his estimate of long-term debt cost of 7.76 percent on his position that NSP failed to completely account for debt refundings which would occur in the test year. He noted a potential $4 million savings from refunding a $100 million pollution control bond (PCB) issue. NSP responded that its long-term debt cost represented its best estimate of refundings and issuances which would occur during the test year. The PCB issue in question could not be refunded until December, 1993 at the earliest, and the $4 million savings quoted by RUD-OAG was an annual figure.

Mr. Kahal argued that the cost of short-term debt should be set at 4.0 percent, rather than the 4.65 percent advocated by the Company. In response to RUD-OAG information requests, NSP indicated that its short-term debt cost for January, 1993 was 3.349 percent. In addition, a survey of major forecasting authorities concluded that commercial paper rates are expected to remain below 4.0 percent during 1993.

The ALJ determined that the appropriate cost of long-term debt for NSP is 8.05 percent. He reasoned that it would be inappropriate to annualize the effect of only one financial transaction on the capital structure, when many other transactions (for example, the $100 million equity issuance) are likely to occur during the test year. The ALJ found that based on NSP's January, 1993 cost of short-term debt, 4.0 percent was the most reasonable number to use for the cost of short-term debt. NSP subsequently agreed to this cost.

The Commission accepts the costs of long-term debt of 8.05 percent, short-term debt of 4.0 percent, and preferred stock of 5.57 percent. The Commission concludes that these costs reasonably reflect the costs expected to prevail for NSP during the test year.

D. Rate of Return on Common Equity (ROE)

1. Legal Guidelines for Commission Decision-Making

In reaching a decision on the appropriate cost of common equity, the Commission, as an administrative agency, must act both within the scope of its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide these general guidelines for Commission rate of return decisions:

a. The allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties;

b. The return should be sufficient to enable the utility to maintain its financial integrity; and

c. The return should be sufficient to attract new capital on reasonable terms.

See <u>Bluefield Water Works and Improvement Co. v. P.S.C.</u>, 262 U.S. 679 (1923), and <u>FPC v. Hope Natural Gas Co.</u>, 320 U.S. 591 (1944).

No particular method or approach for determining rate of return was mandated by those cases, but the necessity of a fair and reasonable rate of return was clearly stated:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. <u>Bluefield Water Works</u>, 262 U.S. at 690.

The Minnesota Supreme Court has also provided some legal guidelines for Commission decision-making. In <u>Minnesota Power & Light Company v. Minnesota Public Service Commission</u>, 302 N.W. 2d 5 (1980), the Court said:

> ...The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function; and (2) the allocation of rates among classes of utility customers, which is a quasi-legislative function.
>
> ...we now hold that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.
>
> 302 N.W. 2d at 9.

In conducting its evaluation of the Commission's decision, the Court explained:

> ...A reviewing court cannot intelligently pass judgment on the PSC's determination unless it knows the factual basis underlying the PSC's determination. Judicial deference to the agency's expertise is not a substitute for an analysis which enables the court to understand the PSC's ruling. Henceforth, we deem it necessary that the PSC set forth factual support for its conclusion. The PSC must state the facts it relies on with a reasonable degree of specificity to provide an adequate basis for judicial review. We do not require great detail but too little will not suffice.
>
> 302 N.W. 2d at 12.

In order to provide the factual basis for its decision required by the Court, the Commission will review the testimony of each of the parties on rate of return on common equity, and the objections raised thereto by other parties. The Commission will also review the recommendations of the ALJ. Finally, the Commission will draw its conclusions from the parties' testimony and determine the proper rate of return.

2. Summary of the Parties' Positions

a. NSP

NSP witness Paul Pender looked at a discounted cash flow (DCF) model, a risk premium model, and a capital asset pricing model (CAPM) to derive the appropriate ROE for NSP. The Company's official position is that the Commission should grant NSP an ROE of 12.5 percent.

The DCF analysis attempts to discern the rate of return required by investors through review of market data. The DCF formula includes two terms: the dividend yield (annual dividends divided by the price of the stock) and the expected growth rate.

Mr. Pender used a standard DCF analysis to estimate the required ROE for NSP. He used the average of the monthly high and low stock prices and dividends paid for the last four quarters ending June 30, 1992, adjusted to account for the increase in dividends for the first year. At the time the case was filed, Mr. Pender calculated the dividend yield to be 6.28 percent. The growth rate was estimated by averaging ten-year (1981-91) historical growth rates in dividends, book value and earnings per share. Mr. Pender used ten years to account for a wide range of economic and financial conditions. He estimated the growth rate to be 5.32 percent. The result of his DCF analysis yielded an ROE of 11.60 percent. In rebuttal testimony, Mr. Pender updated his DCF estimate of ROE to 11.38 percent.

NSP also performed a comparable-group DCF analysis. For its comparable group, NSP selected a group of 20 utilities which were rated AA minus or above by both Standard & Poor's and Moody's and are covered in the Value Line Investment Survey. Mr. Pender calculated a comparable group dividend yield of 6.35 percent and a growth rate of 4.07 percent, for an ROE of 10.42 percent. In his rebuttal testimony, Mr. Pender updated the comparable group DCF estimate of ROE to 10.22 percent.

The RUD-OAG argued that NSP's DCF analysis is flawed because the growth figure is overstated. According to RUD-OAG, investors do not rely exclusively on ten-year data; they also consider shorter periods such as five-year historic periods and analysts' growth estimates in determining growth expectations.

NSP contended that RUD-OAG's criticism of Mr. Pender's analysis demonstrates the inherent subjectivity involved in calculating growth rates using the DCF model. It did not place reliance on five-year trends because they indicate declining earnings which NSP does not anticipate will continue into the future.

NSP believes that the DCF model is limited in its ability to accurately estimate required ROE for companies, and that the results are dependent on the judgment of the person applying the model. It argued that the Commission should consider all the evidence in determining ROE, including its use of the risk premium model and the CAPM.

Mr. Pender presented his risk premium analysis by calculating the average holding period return premium for stocks of the comparable group (20 AA-rated utilities) over those utilities' first mortgage bonds. Based on twenty years of data, he calculated a risk premium of 5.26 percent. Added to the average yield on AA utility bonds of 8.55 percent, the equity risk premium model yields an estimated ROE of 13.81 percent.

In general, the intervenors argued that the risk premium determination was unreliable due to its volatility and uncertainty, and that the method has been consistently rejected by the Commission. RUD-OAG and MEC argued that the results of the risk premium are very volatile depending on the time period used to calculate holding period returns. RUD-OAG witness Mr. Kahal applied the risk premium methodology to the S&P 500 over the period used by NSP and achieved results which suggested that the S&P 500 was <u>less</u> risky than the utility group - a result which defies conventional risk/return theory.

NSP argued that the risk premium method involves simple calculations which are easy to understand. It suggested that intervenors object to the use of the risk premium simply because it produces a high result.

NSP witness Mr. Pender also used the CAPM to estimate NSP's ROE. The CAPM estimates a company's cost of equity by "measuring" its response to systematic risk. The CAPM is applied by calculating a risk premium for the market over a risk free rate and multiplying it by the Company's beta to arrive at a company-specific risk premium, which is added to the risk free rate to arrive at the required ROE. The beta is a comparison of the volatility of a company's stock price (its "riskiness" to investors) with the volatility of prices of the stock market as a whole. The beta is estimated by several services, such as Value Line and Compustat.

Mr. Pender determined the market risk premium using a study by Ibbotson and Sinquefield which covers a time period of 1926 to 1990. The equity market risk premium in the study is 7.2 percent. Using the Value Line beta for NSP of 0.75 and a risk-free rate of 7.67 percent (the average of long-term U.S. Treasury Bonds for the four quarters ending June, 1992), Mr. Pender estimated the CAPM ROE for NSP of 13.07 percent. The CAPM ROE for his comparable group, using an average beta of 0.65, was 12.35 percent.

Intervenors argued that the CAPM is similar to a risk premium method and a great deal of subjectivity exists in estimating the beta. The Department noted that Mr. Pender failed to consider other estimates of beta. RUD-OAG witness Mr. Kahal argued that NSP did not use an appropriate risk-free rate (long-term T-bonds present substantial interest rate risk). In addition, Mr. Kahal performed his own CAPM analysis using an intermediate T-bond and estimated a CAPM ROE of 11.2 percent. MEC argued that the historical data was obsolete and did not reflect current market conditions.

NSP replied that <u>all</u> methods of estimating ROE are subjective, including the DCF method. The CAPM is easily calculated and does not produce the volatile results that certain applications of the DCF method suggest. With respect to RUD-OAG's criticism, NSP argued that a 30-year bond more closely approximates the holding period of a stock than an intermediate bond.

Mr. Pender, using the three models above, calculated a range of ROE for NSP from 11.38 percent (his DCF result) to 13.81 percent (his risk premium result). For the comparable group, he calculated a range of 10.22 percent (DCF) to 13.81 percent (risk premium). He recommended a return of 12.5 percent. To corroborate his studies, Mr. Pender cited 1991 and 1992 return on equity decisions of other state commissions ranging from 10.90 percent to 13.50 percent, and averaging 12.32 percent. NSP-Wisconsin was allowed a 12.0 percent ROE in its most recent rate case, which set rates for a 1993 test year. The North Dakota Commission, on reconsideration, increased NSP's allowed ROE for 1993 rates to 11.5 percent (from 11.0 percent).

NSP argued that returns allowed in other jurisdictions are relevant because NSP must compete nationally with other utilities for equity capital. NSP's ROE must be considered competitive with others or its ability to finance maintenance and construction would be impaired.

MEC noted that in the Order in Docket No. E-002/GR-91-01, the Commission stated that it would not use returns allowed in other jurisdictions if the company could not demonstrate the comparability of the utilities, the rate jurisdictions and the test periods involved in those decisions. According to MEC, NSP had no familiarity with the cases in which the other returns were permitted. RUD-OAG argued that return decisions should be made wholly on the facts related to NSP, and not to other utilities or ratemaking authorities. In addition, 1991 and 1992 decisions are of little use in 1993. The cost of capital has fallen sharply in the last year. The Department noted that basing the allowed ROE on the average of those awarded to other utilities is circular reasoning which bears no relation to NSP data.

NSP reiterated its arguments that other jurisdictions with favorable ratemaking standards (such as interim rates and forecasted test years) consistently authorize returns higher than those granted in Minnesota.

b. Department of Public Service

Department witness Dr. Luther Thompson recommended an ROE of 10.75 percent for the electric utility and 11.50 percent for the gas utility. He relied on a DCF analysis of NSP data and of comparable groups of electric and gas utilities.

Dr. Thompson argued that the electric and gas utilities should receive ROEs which appropriately account for the varying risk of the utilities and appropriately assign cost responsibility among the utilities' customers. If the Commission chose to use a single ROE for both utilities, the Department recommended an ROE of 11.0 percent.

For an NSP-specific return, Dr. Thompson took the average of the 20 day yield (as of January 22, 1993), the third quarter 1992 yield, the one-year annual yield and the two-year annual yield to derive a dividend yield range of 5.9 percent to 6.1 percent. He used 6.0 percent as a reasonable estimate of dividend yield. In determining growth rate, Dr. Thompson looked at 5 and 10 year growth rates on book value per share (BPS), dividends per share (DPS), and earnings per share (EPS) as well as log linear rates, and internal growth rates. He concluded that an appropriate range of growth rates would be 4.0 percent to 6.0 percent. He concluded that the midpoint of that range, or 5.0 percent, was the appropriate growth rate. Therefore, he estimated the cost of equity for NSP at 11.0 percent, within a range of 10.0 percent to 12.0 percent.

To develop rates for the electric and gas utilities, Dr. Thompson performed a comparable group DCF analysis on a group of nine electric utilities and a group of nine gas utilities with similar betas and risk indices. He used the same analysis as was used for NSP-specific data.

For the gas group, Dr. Thompson estimated a dividend yield of 5.6 percent to 6.2 percent and a 5.5 percent growth rate (midpoint of a range of 5.0 percent to 6.1 percent) to determine an ROE range of 11.15 percent to 11.75 percent. He concluded that the approximate midpoint of that range, 11.5 percent, would be an appropriate ROE for NSP-Gas.

NSP criticized Dr. Thompson for failing to adjust his dividend yield for first year dividend growth and for using analysts' growth forecasts. NSP argued that analysts' five-year forecasts are not long-term growth forecasts which are called for in the DCF model. Further, there is no evidence that investors pay attention to these forecasts. In addition, NSP argued that Dr. Thompson failed to include a flotation adjustment, based on his mistaken belief that NSP would not issue common equity in the test year.

Finally, NSP argued that while it is not opposed to the setting of two different returns for gas and electric operations, it seems to add unnecessary complication to the case. NSP is a combination utility, and has only one set of financial objectives for both utilities. NSP witness Mr. Pender did not believe that the risk differences between the two were significant or quantifiable.

The Department argued that the DCF method is the most basic and fair methodology to estimate ROE. The Minnesota Commission has consistently used DCF in making its determinations of appropriate rates of return for Minnesota utilities.

With respect to a flotation adjustment, the Department argued that no significant issuance (in light of the Company's total capitalization) was planned for the year which warrants an adjustment for flotation costs. The Department pointed out that NSP's witness, Mr. Pender, also decided not to make this adjustment.

c. Office of the Attorney General

RUD-OAG witness Mr. Matthew I. Kahal recommended an ROE of 10.6 percent. He relied on a DCF analysis of NSP-specific data and of a comparable group.

Mr. Kahal argued that a comparable group analysis may give the Commission more guidance than stand-alone data because it smoothes out potentially atypical results of individual firms. For his comparable group, Mr. Kahal used the group proposed by NSP, with the exception of one company which was not listed in Value Line. He estimated a dividend yield by calculating the average monthly dividend yield for each company over six months. The average dividend yield for the comparable group, adjusted for growth, was 6.1 percent.

To estimate the appropriate growth rate, Mr. Kahal relied to a substantial degree on the earnings retention method, and also looked at historical growth rates and published analysts' forecasts. Mr. Kahal's application of the earnings retention method yielded an estimated growth rate of 3.75 percent to 4.25 percent. After checking these figures against historical rates and analyst forecasts, Mr. Kahal concluded that an appropriate range of growth rates would be 4.0 percent to 4.5 percent.

Mr. Kahal also proposed a flotation adjustment of 0.1 percent to 0.2 percent to account for the expenses that NSP will incur in issuing stock in the test year. He concluded that an appropriate range of ROE for the comparable group would be 10.2 percent to 10.8 percent.

Using the same basic methodology on NSP-specific data, Mr. Kahal calculated a dividend yield of 6.0 percent, a growth rate range of 4.0 percent to 5.0 percent, and (including a flotation cost adjustment) a cost of equity ranging from 10.1 percent to 11.2 percent. Based on the results of the proxy group (10.5 percent midpoint) and the NSP-specific (10.65 percent midpoint) analysis, Mr. Kahal recommended an ROE of 10.6 percent. He indicated that this ROE was appropriate for both the electric and the gas utilities.

NSP supported the RUD-OAG's addition of a flotation cost adjustment and cited past Commission precedent that flotation costs are included when the utility is issuing common equity in the test year.

d. Minnesota Energy Consumers

MEC witness Mr. Peter Ahn recommended an ROE of 9.4 percent. He used a DCF analysis based on NSP-specific data and a comparable group analysis.

Mr. Ahn calculated a dividend yield using the average monthly high and low stock prices for the three month period of November, 1992 to January, 1993, adjusted for one-half the estimated growth rate. Mr. Ahn's estimated dividend yield was 6.2 percent.

In order to estimate the expected growth rate, Mr. Ahn used three methods: forecasted dividend growth estimates derived from Value Line, an earnings retention analysis using 1991 data, and a projected earnings retention analysis using Value Line projections for 1995 through 1997. He estimated a range of growth rates for NSP at 2.2 percent to 3.2 percent.

Mr. Ahn's comparison group consisted of electric utilities listed with Value Line, excluding companies which were not traded on the New York Stock Exchange or American Stock Exchange, and companies which had decreased or omitted a dividend in the past four quarters. He applied the DCF model to this group, and to three subsets of this group: Companies with a Value Line safety rating of "1," companies with an S&P stock rating of "A," and companies with an S&P bond rating of "AA-." Mr. Ahn's DCF analysis indicated an estimated range of ROE of 9.0 percent to 9.7 percent.

Mr. Ahn also supported his 9.4 percent recommendation with a Merrill Lynch study which estimated a common equity cost for electric, natural gas and telephone utilities in the Merrill Lynch Universe at 10.2 percent. Mr. Ahn reasoned that since NSP's bonds are rated as "AA-," the Company is less risky than the average utility and the 9.4 percent recommendation is supported.

NSP argued that Mr. Ahn's estimate was ridiculously low. It cited recent cases in which Mr. Ahn had been a witness or a witness assistant. In all cases, the recommendation involving Mr. Ahn was the lowest offered, and at least 100 basis points lower than the next lowest witness. In all cases, the Commission awarded ROEs substantially higher than Mr. Ahn's recommendation. In addition, NSP argued that Mr. Ahn could not explain how the Merrill Lynch estimate was calculated or what it represented.

The Department took exception to MEC's almost exclusive reliance on forecasted growth rates, reiterating its position that investors consider all information, including five- and ten-year historical growth rates, in formulating their expectations about growth.

3. Recommendation of the ALJ

The ALJ first determined that it would be more appropriate to view NSP as a single entity, with a single required ROE, than to determine separate ROEs for the gas and electric utilities. The ALJ noted that the combined method is simpler, but the alternative is not overly burdensome. The ALJ chose the unified approach primarily because investors purchasing NSP common stock are forced to look at the combined entity.

The ALJ found that the DCF method continues to be the most appropriate method for determining NSP's required ROE. He further determined that Dr. Thompson's analyses, which are similar to those adopted by the Commission in Docket No. E-002/GR-91-01, continue to produce fair and reasonable results. The ALJ recommended that the Commission adopt a dividend yield of 6.0 percent and a growth rate of 5.0 percent. He further found that the resulting ROE of 11.0 percent should be adjusted to include a flotation cost of 0.15 percent. Because the Company is issuing common stock in the test year, the inclusion of a flotation adjustment is consistent with past Commission practice. The ALJ recommended an ROE of 11.15 percent for NSP.

With respect to other methods proposed by NSP to determine ROE, the ALJ noted that all of those methods were rejected by the Commission in Docket No. E-002/GR-91-01. The ALJ found no compelling reasons in this case to recommend deviation from the Commission's past decisions rejecting these methods in favor of the DCF.

4. Commission Findings and Conclusions

The Commission finds that it is most appropriate to consider a single return on equity for both the gas and the electric utilities. NSP is traded as a combination utility and there is no evidence in the record that NSP investors require different returns for the electric and gas portions of the Company. Additionally, the Commission has generally considered company-specific data, when available, the best indicator of required return on equity. Adopting the Department's analysis would require heavy reliance on comparable groups when company-specific data is available.

The Commission finds that the appropriate return on equity for NSP in the test year is 11.0 percent. In making that determination, the Commission adopts the combined utility testimony of Department witness Dr. Luther Thompson.

The Commission agrees with the ALJ that the DCF method is appropriate for determining the cost of equity for NSP. The DCF method is firmly grounded in modern financial theory, and has been relied on by the Department, RUD-OAG, and MEC in this proceeding and by this Commission in nearly every case decided since 1978. The Commission finds it is reasonable to place primary weight on a direct DCF analysis of data for NSP since NSP is actively traded in the market and its price, dividends and past performance are directly observable.

The cost of common equity cannot be directly observed in the marketplace but can be inferred from market data with the application of reasoned judgment. The DCF method seeks to estimate the return required by investors by using the current dividend yield plus the expected growth in dividends.

After careful evaluation of the record in this case, the Commission concludes that Dr. Thompson's analysis provides the most reasonable balance of long- and short-term market data and expert judgment in determining the appropriate ROE for NSP. Dr. Thompson looked at both shorter (20 day and three month) and longer (one and two year) periods in calculating the dividend yield and estimated a yield of 6.0 percent. The Commission finds that this dividend yield appropriately recognizes and captures expected trends in the dividend yield during the anticipated regulatory period. Dr. Thompson's dividend yield is also corroborated by the DCF analyses of all other witnesses in this case: Mr. Kahal (6.0 percent), Mr. Pender (6.07 percent) and Mr. Ahn (6.2 percent).

While the current dividend yield is fairly easily observed in the market, the determination of the appropriate growth rate is much more subjective. The Commission must determine the rate at which investors expect NSP dividends to grow in the future. In applying the DCF method, it is reasonable to assume that investors place some weight on past growth trends in determining future expectations. The analysis of historical data must be tempered, however, with the consideration of current and expected economic trends.

Dr. Thompson's range of growth rates appropriately captures most of the data available to investors for determining growth expectations. His use of five- and ten-year historic data strikes an appropriate balance between recent trends and long-term stability. The use of analysts' forecasts also captures a broad base of expert opinion on future growth rate trends.

Dr. Thompson selected the midpoint of his growth range, 5.0 percent, as a fair and reasonable estimate of expected growth for NSP. RUD-OAG witness Mr. Kahal included a 5.0 percent growth rate at the upper end of his growth range, and Mr. Pender calculated a DCF growth rate of 5.32 percent. The Commission will adopt a 5.0 percent growth rate as a reasonable balance of the parties' positions.

Although Mr. Kahal's actual growth recommendation of 4.4 percent to 4.5 percent is also included in the reasonable range of growth, the Commission will not adopt Mr. Kahal's recommendation. Unlike Dr. Thompson, Mr. Kahal relied on 1992 data to develop his recommendation. The record in this case demonstrates that the Company's poor performance in 1992 was due to weather conditions which are not expected to reoccur in the near future. Reliance on the 1992 data may have served to lower Mr. Kahal's estimate of growth below that which investors will reasonably require. The Commission finds that a 5.0 percent growth rate is supported by both Dr. Thompson's and Mr. Kahal's testimony.

Combining the 6.0 percent dividend yield with the 5.0 percent expected growth rate, the Commission finds that the cost of equity for NSP is 11.00 percent. The 11.00 percent is based on substantial evidence in the record and will allow NSP the opportunity to attract capital on reasonable terms and maintain its financial integrity.

The Commission finds that NSP has not sustained its burden of proof in demonstrating that the appropriate cost of equity for NSP is 12.5 percent. NSP's request is not reasonably linked to any of the methodologies purported to support it. Mr. Pender performed three different analyses, the DCF with a result of 11.38 percent, the risk premium model with the result of 13.81 percent, and the CAPM with a result of 13.07 percent. He also based his recommendation on returns allowed in other jurisdictions and a forecast of a general economic downturn. The Commission finds that Mr. Pender's analysis lacks the clarity and reliability of Dr. Thompson's analysis.

The Commission rejects NSP's reliance on the risk premium and CAPM models in this case. The Commission has long considered the risk premium model unreliable for use as an estimator of return due to the potential volatility of the results from this method; this record confirms that volatility. The CAPM suffers from many of the flaws of the risk premium analysis as well as the subjectivity involved in determining the beta statistic. The Commission finds that the CAPM is not reliable as a primary indicator of return on equity.

The Commission also finds that there is insufficient evidence in the record to support the use of returns awarded to other utilities in other jurisdictions as a check on the return allowed NSP. NSP offered no evidence as to the comparability of the affected utilities to NSP, nor did it offer evidence as to the comparability of other rate jurisdictions to Minnesota. Furthermore, 1991 and 1992 rate decisions were made based on data for time periods which are likely different from the time periods employed in this 1993 test year.

The Commission rejects Mr. Ahn's analysis, which produces an unreasonably low result. In developing a growth recommendation of 2.2 percent to 3.2 percent, Mr. Ahn failed to take into account NSP's historical growth rates. As noted above, the Commission firmly believes that this information is available to and reviewed by investors in determining their required ROE. In addition, the record is not clear whether Mr. Ahn's growth calculation is derived from NSP-specific data or comparable group data. Finally, Mr. Ahn failed to draw a plausible link between his recommendation and studies which he argued supported that recommendation.

Finally, the Commission rejects the recommendation of the ALJ to add a flotation cost adjustment of 0.15 percent to the required return on equity. The Commission finds that the Company did not request a flotation adjustment and failed to demonstrate that such an adjustment was necessary. In addition, the record did not contain evidence with respect to actual or projected issuance costs.

E. Overall Rate of Return

Based upon the Commission's findings and conclusions on return on equity, cost of debt and preferred stock, and capital structure herein, the Commission finds the overall rate of return for NSP in the test year to be 9.08 percent, calculated as follows:

Capital Employed	Percent	Cost	Weighted Cost
Long-term Debt	38.80%	8.05%	3.12%
Short-term Debt	4.56	4.00	0.18
Preferred Stock	8.26	5.57	0.46
Common Equity	48.39%	11.00	5.32
Total	100.00%		9.08%

XIV. GROSS REVENUE DEFICIENCY

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue deficiency of $54,251,000 as shown below (000's omitted):

Rate Base	$2,373,335
Rate of Return	9.08%
Required Operating Income	$ 215,499
Test Year Net Operating Income	183,203
Operating Income Deficiency	$ 32,296
Revenue Conversion Factor	1.679825
Gross Revenue Deficiency	$ 54,251

In the test year income statement, the Commission found that the total Minnesota jurisdictional revenue at present rates is $1,522,495,000. Adding the gross revenue deficiency of $54,251,000 to this amount results in total authorized Minnesota jurisdictional revenue of $1,576,746,000.

XV. RATE DESIGN

A. Class Cost of Service Study

The Company presented a fully-allocated, stratified, embedded class cost of service study (CCOSS). The starting point for the CCOSS is the results from the jurisdictional cost study. The jurisdictional cost study determines the Minnesota retail jurisdictional share of NSP's total Minnesota Company costs. The jurisdictional study provides the information in the form of plant and expense data by functional group. The functional cost information is the input data for the CCOSS. The CCOSS allocates these costs to the various customer classes based on their respective service requirements.

The class cost of service study provides information on unit costs and rates of return for each class and subclass. The CCOSS is consistent with the studies approved by the Commission in the Company's last three rate cases. However, NSP did institute several small changes that were either ordered by the Commission in the Company's last rate case (Docket No. E-002/GR-91-1) or were initiated by the Company itself.

The changes which the Commission directed NSP to make to its CCOSS include: 1) the exclusion of the Interruptible class from the winter peak demand allocation factor; 2) the allocation of conservation expenses, load management capital costs, and economic development expenses on a cost causation basis; and 3) study and revision, if necessary, of the minimum distribution system cost allocation method. The Company followed the Commission's directive from the last rate case in its filing for this proceeding.

In addition to the Commission-ordered modifications, the Company made several changes involving the allocation of Load Management Rate Discounts, Cash Working Capital and Administration and General Expenses (A&G).

First, the Company proposed to allocate the cost responsibility of Load Management Rate Discounts (Interruptible and Saver's Switch Discounts) to all customer classes. These costs have previously been assigned to the corresponding major class. NSP considers these expenses as a source of peaking capacity and in this proceeding used the same allocator used to allocate the other costs of peaking capacity.

Second, since Property Tax is the major component used to develop Cash Working Capital, the Company suggests that it is a reasonable basis for allocating these costs. The Operation and Maintenance Expenses allocation factor was previously used to allocate Cash Working Capital. The Company believes this allocation factor no longer reflects cost causation.

Third, the Company proposed splitting A&G into greater detail and allocating the components based on cost causation. Previously, Administrative and General Expenses were allocated to classes on an average allocator created by summing total allocated production plant and class energy requirements weighted by time of use.

MEC suggested that in order to properly reflect the costs of serving demand-metered customers by voltage level, as reflected in NSP's CCOSS, the voltage level discounts should be increased.

NSP allocates transmission costs using a weighted summer/winter peak demand factor. MEC indicated that the Company's allocation does not reflect the cost causal factor related to the need for, and the construction of, transmission facilities. MEC recommended that transmission costs be allocated based on class contribution to summer peak demand.

MEC recommended the following modifications to NSP's CCOSS:

1) allocate baseload-related costs based on annual energy usage;

2) allocate transmission-related costs, other than distribution or directly assigned costs, based on class contribution to system summer peak demand;

3) allocate fuel-related costs and non-associated utility energy revenues based on average cost weighted, on-peak and off-peak MWhs; and

4) allocate Other Production energy-related costs on annual energy usage.

The Department reviewed the Company's CCOSS and found that it had not been significantly revised since the last rate case. The Department agreed with, and recommended acceptance of, the minor revisions ordered by the Commission or initiated by the Company and discussed above.

The Department recommended three modifications to NSP's CCOSS. First, because rate discounts result in reduced revenues rather than increased costs, the Department recommended that NSP not include a discussion of load-management discounts in its CCOSS testimony.

Second, the Department recommended that NSP be required to use a stratification method to reflect the functional relationship between energy and capacity in the Company's long-term power purchases. NSP currently uses an energy/capacity ratio which is an average of the ratio for its own facilities, to functionalize purchased power.

The Department believes that NSP's current stratification method is adequate for stratifying its own generating facilities, but that a more accurate method for purchased power capacity payments would be to divide the annual carrying costs of a peaking plant by the annual capacity payments to yield the energy capacity components. The Department indicated that while the current adjustment is not large, the value of stratifying purchased power capacity payments using the Department's method will become apparent in future years as the Company purchases a greater percentage of its capacity needs from third parties.

Third, the Department supported the recommendation of MEC that transmission-related costs be allocated based upon a class's contribution to NSP's summer coincident peak. The Department adopted this position because the primary determinant of transmission-related capacity costs is a utility's annual coincident peak.

The Company argued that the C&I Stipulation agreement incorporates Modified General Service rate options which address MEC's concern that high load factor customers pay more than the cost of service due to energy charges in excess of energy costs. The energy charges MEC refers to are the variable energy charges. MEC does not understand NSP's stratification method and the dual nature of baseload plants in meeting both peak demands and annual energy requirements.

Regarding MEC's recommendation to increase the voltage discounts, the Company suggested that it uses a more precise method to develop energy cost savings associated with higher voltage levels. The Company's analysis begins with separate on-peak and off-peak loss factors weighted by the unique time of day characteristics for each voltage category.

Finally, NSP asserted that its transmission system has many uses and needs beyond the requirement to meet summer peak load conditions. A system which allocates transmission costs based on a summer system peak may distort the class contributions to the transmission needs.

The ALJ found NSP's stratification methodology to be superior to the Department's because it examines each purchased power contract to determine which type of production facility the contract resembles, based on the terms of the contract and the level of capacity payment.

The Judge found the recommendation of the Department to remove the discussion of load management rate discounts from NSP's CCOSS to be appropriate.

The ALJ rejected MEC's proposed modifications to the allocation of production baseload costs, fuel-related costs and energy related costs, which have the effect of increasing NSP's demand charges and decreasing energy charges.

The ALJ found that NSP's allocation of transmission costs considers all monthly peak load levels to determine the seasonal weighting factors applied to summer and winter coincident peaks and that it is appropriate to maintain that methodology. The methodology used by NSP is superior to that proposed by MEC. Therefore, the modifications recommended by MEC and supported by the Department should be rejected. The methodology used by the Company is sound, consistent with the method approved by the Commission in the past, and should be maintained.

The ALJ stated that, given the fact that the CCOSS uses average loss factors leading to less precise voltage discounts, MEC's proposed voltage discount adjustment is inappropriate. If the energy-related capital costs of baseload and intermediate units, as well as some capacity payments for power purchases, are included into the savings and energy costs attributable to service at primary and transmission voltages, those savings are identical to the voltage discounts proposed by the Company.

The Commission agrees with the ALJ's findings on the Company's class cost of service study and finds that the only appropriate modification to the Company's proposal is the Department's recommendation to require the Company to remove the discussion of load management discounts from its CCOSS. Rate discounts result in reduced revenues rather than increased costs and the Commission finds that it is inappropriate to include these costs in the CCOSS.

The Commission finds the Company's purchased power stratification methodology to be superior to the Department's because it examines each purchased power contract to determine which type of production facility the contract resembles, based on the terms of the contract and the level of capacity payment.

The Commission agrees with the ALJ that it is appropriate to reject the recommendations of MEC to modify the CCOSS to allocate more costs on the basis of demand. The Commission recognizes the dual nature of baseload plants in meeting both the peak demands and the annual energy requirements of customers. The Commission observes that the total energy-related costs shown in the Company's CCOSS, including the energy-related portion of baseload plants, are actually greater than the energy charge proposed by the Company.

The Commission will not accept the proposal of MEC, supported by the Department, to allocate transmission costs according to each customer's contribution to a single summer peak. The peak use of the transmission system may very well occur at different times than the summer peak hour. To allocate transmission costs based solely on the summer peak may distort the actual class contributions to transmission needs.

The Company's allocation methodology considers all monthly peak load levels when determining the seasonal weighting factors to be applied to the summer and winter coincident peak demands. The Commission finds that NSP's methodology is sound, consistent with the methodology approved by the Commission in the past and should be maintained.

The Commission agrees with the Company, the Department, and the Administrative Law Judge that MEC's recommendation to increase the voltage discounts should be rejected. The energy cost savings attributable to service at primary and transmission voltage, as developed in NSP's CCOSS, are identical to the Company's proposed energy voltage discounts in its applicable tariffs.

B. Class Revenue Responsibilities

NSP asserted that the main objective of its proposed revenue responsibility is to reflect the cost of providing service and to minimize cross-subsidies between classes and subclasses. The CCOSS presented by the Company in this proceeding indicated that major classes were paying rates that were close to cost.

However, NSP claimed that a Residential class subsidy remains, which is now borne by the Commercial and Industrial class. In an attempt to reduce the Residential class subsidy, while maintaining reasonable continuity with past rates, the Company proposed to distribute the proposed 8.98 percent overall increase as follows: an 11.2 percent increase to Residential customers, a 7.9 percent increase to C&I customers, a 9.6 percent increase to Sales to Public Authorities and a 1.8 percent increase to Lighting customers.

The Department did not object to NSP's proposed revenue apportionment to the major classes and recommended that they be adopted. However, the Department recommended that an adjustment be made within the Public Authorities class. The Department proposed that the revenue responsibility of the Municipal Other subclass be adjusted in order to increase the revenue-to-cost ratio from 42.06 percent to 45 percent. The increase would be offset by a decrease in the revenue-to-cost ratio of the Municipal Pumping subclass.

MEC proposed that any increase to Commercial & Industrial customers be recovered entirely from the demand charge, which will promote demand conservation through proper price signals. MEC argued that NSP's energy charges for General Service customers are well in excess of energy costs, which results in high load factor customers paying more than their cost of service.

The ALJ recommended an overall increase of 3.78 percent. The ALJ found it appropriate to adjust NSP's proposed revenue allocations by the ratio of 8.98 percent (the original overall increase proposed by NSP) to 3.78 percent, or a factor of 2.38. The ALJ also found that the adjustments advocated by the Department and MEC (discussed in the class cost of service study section) were inappropriate.

The Commission finds that the revenue allocation to major classes proposed by NSP is reasonable, when adjusted proportionately for the lower revenue requirement ordered herein. The class revenue allocation is consistent with the results of the Company's CCOSS adopted by the Commission. The proposed allocation will reduce the Residential class subsidy while maintaining continuity with past rate levels for major customer classes.

C. Residential and Small Commercial & Industrial

1. Basic Residential Service

The basic design of the Residential Service rates is consistent with the Order in NSP's last rate case, in which the Commission adopted separate space heating and non-space heating (standard) rates with flat energy charges. The Company proposed to maintain the current customer charges for non-space heating customers of $4.50 and $6.50 for overhead and underground, respectively. The Company also proposed to increase the customer charge for space heating customers by $1.00 to $6.00, and for overhead and underground service by $1.00 to $8.00. The summer season energy charge is 7.76 cents per kWh for both standard and space heating customers. The winter season energy charge for regular customers is 6.76 cents per kWh and 5.14 cents per kWh for space heating customers.

The Department supported the Company's proposals for space heating customers but recommended that the Commission increase the customer charge for standard customers by $0.50 to $5.00. The Department argued that the increase in the customer charge would allow the Company to recover more of its fixed costs in the fixed customer charge instead of the variable energy charge, thereby contributing to the revenue stability of the Company.

The RUD-OAG opposed the Department's recommendation to increase the customer charge for standard Residential customers. The RUD-OAG argued that the Department's proposal to move the customer charge closer to average embedded cost does not promote the proper price signal because average embedded costs are not marginal costs and do not reduce costs for price sensitive customers in other classes. Further, the RUD-OAG argued that the Department's proposed customer charge would reduce the incentive for energy conservation and efficiency improvements.

The ALJ found the Company's proposal to increase the customer charge for space heating customers to be appropriate. The ALJ found the Department's proposal to increase the customer charge for basic Residential service to be inappropriate, particularly in light of the proposed reduction to the Conservation Rate Break (CRB).

The Commission agrees with the ALJ that the Company's proposal to increase the customer charge for space heating customers is an appropriate reflection of the higher fixed costs of serving these customers. The Commission finds the Department's recommendation to increase the customer charge for basic Residential service to be inappropriate, at this time. The Commission acknowledges the Department's argument that increasing the customer charge would enhance the utility's revenue stability; however, such an increase would have a negative impact on low use Residential customers. In light of the reduction to the CRB credit for small users, the Commission rejects the Department's proposal.

2. Residential Inverted Rate Structure

The Minnesota Senior Federation (Senior Federation) proposed an inverted rate structure, in which successive blocks of increased kWh usage are priced at successively higher prices. According to the Senior Federation, such a rate would make customers contribute revenues in proportion to their contribution to peak demands. The Senior Federation submitted load data which it claimed provided cost support for its proposed rate structure.

NSP argued that there are significant flaws in the Senior Federation's analysis. The data used by the Senior Federation is for average summer and winter weekdays only, instead of the more relevant peak days. Also, the Company indicated that load research data shows no direct relationship between higher total monthly consumption and progressively higher contributions to the system energy requirements during individual high cost hours of the month.

The Department argued that inverted or inclining block rates are economically justified when the per-unit cost of providing service to a customer increases with a customer's cumulative consumption. This is not the case for NSP's customers. NSP's cost of providing energy varies by season, time of day and temperature but there is no evidence that the cost of providing service varies with a customer's total consumption.

The ALJ found it appropriate to reject the Senior Federation's inverted block rate proposal. Time-of-use rates, including rates that vary by season, send price signals superior to those sent by the rate design advocated by the Senior Federation.

The Commission rejected the Senior Federation's proposal for an inverted block rate structure in NSP's last general rate case, Docket No. E-002/GR-91-1. The Commission finds, as it did in NSP's last general rate case, that the inverted rate structure proposed by the Senior Federation is not supported by the cost information in the record.

The load data supplied by the Senior Federation in this proceeding shows that all sizes of Residential customers tend to use electricity similarly during the day; higher use customers do not seem to consume a disproportionate amount of their electricity on-peak when compared to lower use customers. The Senior Federation's data indicates that customers who use more energy also tend to have higher demands. However, they also pay higher bills. The Commission finds that flat Residential rates reasonably account for increased costs related to increased use.

3. Conservation Rate Break

The Conservation Rate Break provides rate credits to customers who consume 400 kWh or less per month. The CRB was originally intended to promote conservation by lowering the customer charge. In the Company's last rate case the Commission found that the CRB was not a cost effective means of promoting conservation or of meeting the needs of low income customers. The Commission approved the Company's proposal to reduce the CRB from $3.50 to $2.50 for monthly consumption of 300 kWh or less, and from $1.75 to $1.25 for monthly consumption of 400 kWh or less. NSP's proposal in this proceeding was to continue the phaseout of the CRB by reducing these credits to $1.50 and $0.75 respectively.

The Department did not object to NSP's proposal to reduce the CRB. The Department indicated its belief that Conservation Improvement Programs are better vehicles for promoting cost-effective conservation.

The RUD-OAG stated that NSP's proposal to reduce the Conservation Rate Break will encourage even less conservation than it has so far. The lower CRB will provide less relief than the current level for low-income customers who happen to receive it.

The Administrative Law Judge found NSP's continued phaseout of the CRB to be an appropriate means of maintaining consistency with the Order in NSP's 1991 rate case. Also, the record contains no opposition to the continuing phaseout of the credit.

In the Company's last general rate case the Commission recognized the shortcomings of the CRB, both as a mechanism to promote conservation and as a vehicle for providing affordable electricity to low-income customers. The Commission finds nothing in this record to cause it to reach a different conclusion on the shortcomings of the CRB. The Commission will adopt NSP's proposal to continue the phaseout of the CRB credit in this proceeding.

4. Low Income Discount Rate

In NSP's last rate case the Company proposed to reduce the Conservation Rate Break and eventually phase it out. The Commission accepted the Company's proposal and agreed that the CRB was not a cost-effective means of promoting conservation or of providing assistance to low-income customers. The Commission ordered the Company to examine possible ways to provide affordable electricity to customers with low incomes and special medical needs and to provide the results of its examination in its next rate case.

NSP indicated that it is willing to do whatever it can reasonably and effectively accomplish as an energy provider to mitigate the problems faced by low-income customers. The Company believes, however, that utility rates are an inappropriate mechanism to address what is essentially an income problem.

The Company provided an example of a low-income discount in its initial filing. The example is a 15 percent discount to the bills of customers who have been identified by social service agencies as qualifying for the Energy Assistance Program (EAP).

NSP estimated that 50,000 customers within its service territory would qualify for the discount. The total cost to provide the discount to these customers would be about $3.2 million annually. The average monthly bill of qualifying customers is approximately $36.00 and the 15 percent discount would reduce the average bill by $5.40.

The Company discussed several of the problems that might occur if a low-income discount rate is offered. First, regardless of how the program is designed there would be deserving customers who would not qualify. The Company and the Commission would need to be prepared to deal with these situations. Second, the cost of the discount program would likely be financed through the energy charge to all Residential ratepayers. The Company, as well as the Commission, would need to explain and justify these additional costs. Finally, the Company argued that providing assistance to low-income customers through their utility bill may have a "neutralizing effect" on the assistance these customers receive from other social services.

The Company also identified several difficulties in designing and administering a discount rate for special medical needs customers. First, not all customers with special medical needs have an ability to pay problem. Second, the need to provide a discount to customers with special medical needs is merely part of the more general ability-to-pay problem discussed above. Third, there are several administrative and practical problems associated with providing a discount to customers with special medical needs. Some of these problems include determining what medical conditions or end uses should qualify for assistance, how much of the customer's total electric use would qualify for assistance, how often the account would have to be certified, and which class or classes should help finance the discount.

NSP argued that there are two questions the Commission needs to answer to determine whether a low-income or special medical needs discount should be provided. First, are utilities and hence utility rates the appropriate mechanism to redistribute income from customers of a certain income level to customers whose income is below that level? Second, if utility rates are the appropriate mechanism for redistributing income to low-income customers, how should it be done?

The Department argued that the needs of low-income customers should be addressed through the social welfare system and not through utility rates. The Department indicated that while some of the problems identified by the Company in implementing a discount rate could be overcome, others might not.

The Department shared the Company's concern that other ratepayers would have to fund the discounts provided to low-income customers. While some ratepayers would not object to paying slightly higher rates in order to provide assistance, others likely would object.

The Department asserted that a voluntary program would eliminate some of the concerns of the Company. For example, if voluntary contributions are solicited for funds established by other entities, the Company will not duplicate the efforts of others and NSP would incur minimal administrative expenses. Also, the program would be voluntary and therefore ratepayers who did not wish to participate would not be affected.

Finally, if the Commission determines that a low-income discount rate is appropriate, the Department recommended that the discount be set at the level of the customer charge in order to minimize the usage-sensitive price signal.

In response to the Commission's directive to discuss the possibilities for establishing a low-income and special medical needs discount, the RUD-OAG provided extensive testimony in support of providing assistance to low-income customers.

The RUD-OAG made two recommendations for low-income assistance. First, the RUD-OAG recommended that NSP implement a low-income discount rate for qualifying customers. The discount rate would replace the Conservation Rate Break and would target $7.2 million in rate relief. Qualifying customers would be identified by Minnesota's Energy Assistance Program. The discount would provide a 75 percent credit to the monthly bill or a $12.00 credit, whichever was less. The monthly cost of the program to other individual ratepayers was estimated at 65 cents.

The second recommendation of the RUD-OAG was to establish a collaborative to design an experimental rate for payment-troubled customers. The collaborative would include NSP and various interested parties, including low-income customers and their advocates, social service agency representatives, and low-income conservation suppliers. The RUD-OAG argued that such a rate is needed because of the potential to reduce the costs related to servicing these accounts, while improving the quality of service for payment-troubled customers. Many payment-troubled customers do not have the ability to pay their utility bills at existing rates but may have the ability to pay for the variable costs associated with providing service and make some contribution to fixed costs. According to the RUD-OAG, such a rate has the potential to increase both efficiency and equity, and should therefore be developed.

The Energy Cents Coalition (ECC) also provided extensive comments supporting the establishment of a low-income discount rate. ECC's comments sought to refute many of the concerns expressed by the Company and the Department concerning the implementation and administration of a low-income discount. ECC's comments also provided several examples of low-income persons who are in need of financial assistance to pay for the basic necessities of life.

The ECC recommended that the Commission order NSP to establish a discount rate for low-income customers. The discount would be funded using the funds presently used to provide the Conservation Rate Break, would be tied to further conservation efforts, and would include a waiver of the monthly customer charge. ECC's goal in the rate case proceeding was to establish a discount rate and, after that, have NSP work with EAP providers to create the most effectively administered program possible.

The ALJ found it appropriate to reject the low-income rate discount proposed by the RUD-OAG. However, the ALJ recommended the Commission adopt the RUD-OAG proposal to initiate a collaborative to develop a low-income rate for payment-troubled customers. The ALJ indicated his belief that these problems should be addressed through the social-welfare system and not through electric rate design.

The Commission recognizes the genuine financial hardship faced by many low-income citizens in the State of Minnesota. Moreover, the Commission fully supports the need for additional and timely low income energy assistance from federal, state and other sources. However, the Commission believes that this problem should be addressed on a statewide basis in order to ensure equitable coverage and consistency. It looks to the legislature for policy guidance and direction in this matter.

The Commission finds that to establish a discount rate to assist only NSP's low-income customers is inappropriate. To single out an individual utility and require its ratepayers to provide assistance to low-income customers is inequitable. NSP customers are not uniquely responsible for subsidizing the energy consumption of low-income citizens, above and beyond the responsibility borne by other citizens of the State of Minnesota.

The Commission notes that assistance to low-income individuals has traditionally been the responsibility of society at-large and the social welfare system in particular. The Commission is not, at this time, prepared to transfer this responsibility to the ratepayers of Minnesota. The Commission is not convinced that utility rates are the appropriate vehicle by which to provide additional low-income assistance.

The Commission agrees with the Department that many of the concerns identified by the Company regarding the implementation of the discount rate could be addressed. Many of the concerns asserted by the Company have more to do with the type and level of assistance which would be provided rather than with the wisdom of providing assistance in the first place. The fact that NSP and the Commission would be required to deal with certain difficulties resulting from the implementation of a discount rate is not the critical issue. Many of the issues the Commission must address are ongoing and not simply resolved in one proceeding.

As an alternative to a low-income discount rate, the Department recommended that the Commission encourage NSP to solicit voluntary contributions from its customers to fund programs aimed at providing emergency assistance to low-income households. NSP currently participates in soliciting funds from its customers for the HeatShare program which provides heating assistance for eligible senior citizens, disabled persons and families. The Department indicated that NSP could initiate additional efforts designed to assist low-income customers in paying their electric bills.

The Commission applauds the Company's participation in the HeatShare program. The Commission supports the concept of a voluntary program to solicit funds to assist low-income customers to pay their electric bills and encourages the Company to investigate the potential for such a program. However, the Commission will not order the Company to establish a voluntary program at this time.

5. Controlled Air Conditioning and Water Heating Rider

Customers who allow the Company to control their central air conditioning and water heating during system peak periods receive an energy charge discount. NSP proposed to add a kWh limit to which the discount can be applied. The Rider is available to Residential and Small C&I customers. The proposed limit is 4000 kWh, which applies to both the air conditioning and the water heating discounts. The Company also proposed to remove the term "Experimental" from the title of the Rider.

No party objected to the Company's proposals. The ALJ found the changes to be reasonable, and recommended approval.

The Commission agrees that the Company's proposal to remove the term "Experimental" from the title of the Rider is appropriate. The Saver's Switch program has proven to be an effective demand-side management program and should no longer be considered an experiment. The Commission finds that it is reasonable to establish a kWh limit to which the discount is applicable for both the air conditioning and water heating discounts.

6. Optional Trial Service for Residential, Small General and General Service Time of Day (TOD) Tariffs

The Company proposed to eliminate the limit on the number of customers eligible for the three months Optional Trial Service for Residential TOD customers. The Company also proposed to begin offering a similar Optional Trial Service to Small General TOD and General TOD Service customers. NSP hopes to encourage more customers currently on firm service tariffs to experiment with TOD rates. If a customer chooses not to remain on the TOD rate, the customer will pay a charge to cover the Company's cost of removal of the time of day metering equipment.

The ALJ stated that the Company's proposal to remove the maximum limit on the number of customers eligible for the Optional Residential TOD Service and to begin offering the Optional Trial Service to Small General TOD and General TOD Service was unopposed, reasonable and appropriate for adoption.

The Commission agrees with the ALJ that the Company's proposals are appropriate. The purpose of TOD tariffs is to make more efficient use of a utility's system by providing cost-based time of use rates which may encourage customers to move their demand off-peak. The Commission believes that allowing customers a three month trial period to become familiar with the rate and to determine whether the customer can benefit from TOD rates is a proper method to promote the most efficient use of NSP's system.

7. Residential and Small General Service Time of Day Rates

Residential TOD and Small General TOD Service rates consist of a customer charge and an energy charge. The Company proposed to modify its Residential and Small General Service TOD tariffs to maintain their consistency with the standard rates. Distribution costs and customer costs not included in the customer charge are incorporated into the off-peak energy rate. The Company determined its on-peak energy charges so that the on- and off-peak energy charges, when weighted by the class on- and off-peak usage percentages, will equal the energy charge for the standard rate. NSP's approach in determining the on- and off-peak energy charges is unchanged from the Company's approach in its last rate case filing.

The Company is also proposing to reduce the customer charge for both rate schedules to reflect lower metering costs and to help encourage customers to switch to TOD rates voluntarily. The present customer charge includes TOD metering costs of $4.50 for Residential TOD Service and $5.25 for Small General TOD Service. NSP proposes to reduce this component to $2.00 per month.

The Department provided extensive testimony on the issue of TOD pricing. The essence of the Department's approach to determining time of day rates is that they be set as closely as possible to marginal capacity costs. However, in order to allow NSP to attain its Commission-approved revenue requirement, the Department suggested that the second best approach is to set the energy charges so that the on-peak to off-peak ratios are similar to the corresponding ratio of marginal costs. The Department contended that NSP's proposed TOD rates fail to reflect marginal costs with sufficient accuracy, leading to a less efficient use of the Company's system.

The ALJ suggested that the main goal of TOD rates is to send appropriate price signals to customers. Economic theory would suggest this is best accomplished through marginal cost pricing, which can only be accomplished with accurate and reliable cost data. Application of that data must not cause frequent and significant deviations from current rates.

The ALJ found that the Department relied upon questionable data in forming its proposal and did not address the resulting significant change in rates. The ALJ recommended that the Department's proposal to base TOD rates strictly on marginal cost data should be rejected. The ALJ found the Company's proposed rates to be reasonable and appropriate for adoption.

The Commission agrees with the ALJ and finds that the Company's proposed rates for Residential TOD Service and Small General TOD Service are reasonable and appropriate for adoption. As indicated in other sections of this Order discussing rates for time of day tariffs, the Commission does not support strict marginal cost pricing for these rates based on the Company's 1989 marginal cost study. The Commission agrees with the ALJ that the data from that study is of questionable value for setting rates today.

8. Small General Service

NSP presently sets the energy charges for Small General Service (SGS) equal to those for Residential Service. The Company proposed to change its pricing policy to make the SGS rate more consistent with the General Service tariff and to more closely reflect the cost of service. Specifically, the Company proposed to increase the customer charge from $6.60 to $7.00 per month and the energy charges from 6.03 cents to 6.55 cents and 6.83 cents to 7.55 cents per kWh for the winter and summer seasons, respectively.

The Department supported the Company's proposals for this rate and indicated that the proposed rate will provide a better transition for customers who transfer from Small General Service to General Service. The ALJ found the Company's proposed modifications to be appropriate.

The Commission finds that the Company's proposal to make the SGS rate more consistent with the General Service tariff and to more closely reflect the cost of service to these customers is appropriate, when adjusted for the lower revenue requirement. The Commission agrees with the Department that the proposed rate will provide a better billing transition for customers who transfer from Small General Service to the General Service tariff.

9. Energy-Controlled Service (Non-Demand Metered)

The Company proposed one modification to this rate. The commercial rate for the Optional Energy Charge was increased to equal the Small General Service summer energy charge. The customer charge was increased from $2.75 to $2.90 with the energy charge set at 3.52 cents per kWh.

In addition, two changes were made to the Terms and Conditions of Service. First, number 1 was changed to allow the customer the choice of operating equipment on firm or controllable service. Second, number 7 was revised to simplify the installation process and allow the Company to utilize a radio-activated control system for more accurate and consistent control.

No party opposed these modifications. The Department agreed with the Company's proposed changes. The increase in the customer charge is a moderate increase which moves the charge closer to the cost of service, and the proposed changes to the terms and conditions of the tariff should make it easier for customers to participate. The ALJ found the proposed modifications to be appropriate.

The Commission agrees with the Department and the ALJ that the Company's proposals for the Energy-Controlled Service (Non-Demand Metered) are appropriate for adoption, when adjusted for the lower revenue requirement.

10. Limited Off-Peak Service

NSP proposed two modifications to the design of this rate. First, NSP proposed creating separate customer and energy charges for Residential and Commercial/Industrial (C&I) customers. Second, the Company developed corresponding customer and energy charges for higher voltage customers, including transmission transformed and transmission level voltages.

No party opposed the modifications. The Department agreed that Residential and C&I customers on this rate should pay different customer charges and that the new levels proposed by NSP appropriately recognize different customer usage and cost characteristics. The ALJ found the proposed modifications to be appropriate and recommended adoption.

The Commission agrees with the Department and the ALJ that the Company's proposed modifications to the Limited Off-Peak Service tariff are appropriate for adoption, when adjusted for the lower revenue requirement.

D. Commercial & Industrial

On April 14, 1993, NSP and seven Commercial and Industrial (C&I) intervenors entered into a Stipulation Agreement regarding the following C&I rate design issues: Experimental Demand Free Power Service Rider; Energy-Controlled Service Rider; Experimental Peak-Controlled TOD Service; Modified General Service and Modified General TOD Service; Peak-Controlled Tiered Service and Peak-Controlled Tiered TOD Service. The Department did not sign the Agreement and presented evidence in opposition to certain parts of it. The Department also argued as a procedural matter that the Agreement was not a settlement within the meaning of Minn. Stat. § 216B, subd. 1a (1992) and should not be referred to as such by the Commission because the Department had not signed it.

On June 7, 1993, the ALJ issued an Order Recommending Acceptance of Stipulation Agreements. The ALJ found that the C&I Stipulation Agreement was reasonable, supported by substantial evidence in the record, and would result in just and reasonable rates. He also found that the Agreement was a settlement within the meaning of Minn. Stat. § 216B.16, subd. 1a (1992). The ALJ further recommended that the Stipulation Agreement be accepted by the Commission as resolving the rate design issues encompassed therein.

The Commission determined that the record was sufficiently developed on each of the rate design issues contained within the Stipulation Agreement. The Commission decided to make decisions upon the rate design issues on an individual basis, rather than collectively. Since the Commission accepted the rate design proposals suggested by NSP and the seven C&I intervenors, it is not necessary to reach the issue of whether the Agreement was a settlement within the meaning of Minn. Stat. § 216B.16, subd. 1a (1992). The Commission will discuss the five proposed categories of rate design issues from the Stipulation in turn, followed by a discussion of several C&I issues not presented in the Stipulation.

1. Experimental Demand Free Power Service Rider

NSP proposed an Experimental Demand Free Power Service Rider to allow customers with additional short-term needs to increase their electrical demand without incurring additional incremental demand costs. The Rider is available only when NSP has surplus capacity. Under the Rider a customer can operate its facility above its contract demand without paying for a higher demand level placed on NSP's system.

The Department was concerned that customers on the Rider would contribute to the Company's capacity requirements and that these customers would receive capacity at the rates charged for service under the Rider, when they would have been willing to pay the standard rate. The Company addressed these concerns by making the Rider available only when it has excess capacity and by requiring customers receiving service under the Rider to have a load factor of not less than 80 percent. Therefore, the Department now supports offering this tariff on an experimental basis, as modified.

The ALJ found the proposed tariff to be based on substantial evidence in the record, in the public interest and reasonable for adoption.

The Commission will approve for a two year experimental period the Company's proposal to establish a Demand Free Power Service Rider. The modified proposal will provide additional flexibility to customers without adversely affecting other ratepayers.

2. Energy-Controlled Service & Energy-Controlled Service Rider

NSP proposed to close Energy-Controlled Service to new customers and to phase it out. The Company has maintained the basic design of the rate. The controllable demand discount of $3.27 per kW month was unchanged. However, the controllable energy charge discounts were reduced by one-third, as part of the Company's proposal to phase out this service schedule.

Many of the changes made to the Peak-Controlled Service tariff were also made to the Energy-Controlled Service tariff. The voltage discounts correspond to the levels proposed for General Service and the failure to control penalty was changed to $10.00 per kW for every load control failure, instead of the existing $13.80 per kW applicable only once every month. The tariff language was revised to incorporate the Annual Minimum Demand Charge provision and a list of the items which must be included in the electric service agreement.

The Department had initial concerns with the Company's proposal to close this tariff. The Department argued that the Energy-Controlled tariff should remain open until NSP modifies the Peak-Controlled tariff to allow the Company to interrupt customers when its marginal energy costs are high, and customers in both tiers are provided with corresponding discounts for their additional commitment. The Department asserted that there is a value to the Company to be able to interrupt customers during high cost energy periods.

North Star Steel Praxair recommended that the Company modify its proposal to allow customers taking service on the TOD rate the additional option of Energy-Controlled interruptible service.

The Company responded to the parties by proposing an Energy-Controlled Service Rider for Peak-Controlled Tier 1 TOD Service. The proposal allows existing Energy-Controlled customers to receive service under the Peak-Controlled Tier 1 TOD schedule along with the additional requirements and discounts associated with Energy-Controlled service. The Company proposed to restrict the availability of the Rider to existing Energy-Controlled Service customers until the rate has been fully evaluated and presented to the Commission for permanent approval.

The ALJ found NSP's proposed modifications and proposal to close the Energy-Controlled tariff to new customers to be appropriate. The ALJ also found the proposed tariff to be based on substantial evidence in the record, in the public interest and reasonable for adoption.

The Commission finds the proposed modifications to the existing Energy-Controlled Service to be reasonable. The Commission finds that since the proposed Energy-Controlled Service Rider maintains the Company's ability to interrupt customers when its marginal energy costs are high, the proposal to close Energy-Controlled Service to new customers and to eventually phase out the schedule altogether, is appropriate. The Commission finds the Company's proposal for the Energy-Controlled Service Rider to the Peak-Controlled Tier 1 TOD Service tariff to be appropriate. The Commission agrees with the Department that there is value to the Company in being able to interrupt customers when its marginal energy costs are high.

3. Experimental Peak-Controlled TOD Service

On February 1, 1993, the Company petitioned the Commission for approval of an Experimental Peak-Controlled TOD Service tariff (Docket No. E-002/M-93-80). The proposed tariff would make three-period TOD service available to interruptible customers and would complement the previously approved Experimental General TOD Service. On May 25, 1993, the Commission issued its ORDER APPROVING EXPERIMENTAL TIME OF DAY TARIFF ON AN INTERIM BASIS. The Commission declined to make a final determination on the appropriateness of the rates for this proposal in the miscellaneous docket and indicated its intent to address this issue in the context of the Company's rate case.

The Company's proposal allows interruptible customers to qualify for a three-period TOD rate. Participation in the experiment is limited so that the total number of customers between the proposed three-period Experimental Peak-Controlled TOD Service tariff and the previously approved three-period Experimental General TOD Service tariff will be no greater than 30. The energy and demand charges for the proposed Experimental Peak-Controlled TOD Service tariff were developed to maintain consistency with already existing tariffs. The Company suggested that the experimental tariff should be adjusted to maintain consistency with existing tariffs and the Commission's final decision in the general rate case.

The Department provided extensive testimony on the issue of time of day pricing. The essence of the Department's approach to determining the appropriate time of day rates is to set them as closely as possible to marginal energy and capacity costs. However, in order to allow NSP to attain its Commission-approved revenue requirement, the Department suggested that the second best approach is to set the energy and demand charges so that their on-peak to off-peak ratios are similar to the corresponding ratios of the appropriate marginal costs. The Department argued that TOD rates should be set to promote the efficiency of NSP's system and not necessarily to maximize the number of customers taking service under TOD rates.

The ALJ found the proposed tariff to be based on substantial evidence in the record, in the public interest and reasonable for adoption.

The Commission finds the proposed Experimental Peak-Controlled TOD Service tariff, as proposed by the Company, to be appropriate, when adjusted for the lower revenue requirement. As indicated in other sections of this Order discussing rates for time of day tariffs, the Commission does not support strict marginal cost pricing for these rates based on the Company's 1989 marginal cost study. The Commission agrees with the ALJ that the data from that study is questionable for setting rates in this proceeding.

4. Modified General Service and Modified General TOD Service

The Company proposed minor refinements to the rate structure for the General Service schedules. The demand charge discounts for the higher voltage services of primary, transmission transformed and transmission service have been increased to reflect current costs. The Company is proposing a percentage increase in the demand charges which is slightly more than the overall increase for the General Service class. Correspondingly, the proposed increase in the energy charge is slightly less than the overall class percentage increase. The demand charge differential between summer and winter has also been increased, resulting in a larger increase for summer demand charges than for the winter demand charges.

The Company argued that the purpose of the proposed changes is to respond to the concerns of large C&I customers who are interested in a rate design with higher demand charges and correspondingly lower energy charges.

In its initial filing the Company solicited comments on a Large General Service rate (LGS). LGS customers would generally be large in size and/or have a high load factor. Large C&I customers generally have a higher load factor and a more favorable time-of-use load pattern than other C&I customers. The Company suggested that this type of customer utilizes NSP's system more fully and therefore the cost to serve them should reflect these differences.

The Company did not initially propose the adoption of an LGS rate because of the uncertainty in the level of interest for such a rate and because of the changes being considered to the Company's General TOD Service and the general Controlled TOD Service schedules.

The Company proposed modifying the General Service and General Service TOD rate to include an energy charge discount of 0.70 cents per kWh for energy in excess of 400 hours use, limited to 50 percent of any customer's total energy use. The proposal is the equivalent of the LGS rate on which NSP was soliciting comments. The Company argued that the energy charge discount of the Modified General Service and Modified General TOD Service schedules would offer the added benefit of not requiring a separate tariff, and customers would automatically be billed at the appropriate rate for their usage patterns.

Champion International Corporation (Champion) recommended that rather than simply receive comments on the LGS rate, the Commission should order NSP to implement an hours-use energy block based on the customer's peak billing demand. NSP's Modified General Service and Modified General TOD Service schedules incorporate the changes recommended by Champion.

Minnesota Energy Consumers argued that both large and small high load factor customers are overcharged by a flaw in NSP's rate design. MEC asserted that the creation of a new rate is not the solution to the overcharging of high load factor customers.

The Department opposed the Company's proposed modified tariffs. The Department indicated that it supports separate tariffs for customers who share the same cost and usage characteristics; however, these separate tariffs must be based on a thorough analysis of all the costs of serving these groups of customers. The Department asserted that the Company has not done this. The Department recommended that the Company be required to conduct a class cost of service study that separates the General Service class into appropriate segments.

Specifically, the Department opposed the 0.70 cent discount for all consumption in excess of 400 kWh per kW of monthly billing demand. The Department argued that while the discount is based on the reasonable assumption that the per-unit cost of service decreases as a customer's non-coincident load factor increases, there is no quantitative support for the proposed discount or cost-based reason for establishing the threshold of 400 kWh per kW of billing demand.

The ALJ found the proposed tariffs to be based on substantial evidence in the record, in the public interest and reasonable for adoption.

The Commission finds the proposed modifications to the rates of the Modified General Service and Modified General TOD Service to be reasonable. The Commission finds that the Company's proposed addition of an energy charge discount to the Modified General Service and Modified General TOD Service schedules to be appropriate for adoption. The Commission agrees with the Department that customers who share different cost and usage characteristics should have separate tariffs. However, the Commission believes that an energy charge discount for high load factor customers has merit and will not require the Company, at this time, to provide specific cost data supporting the implementation of the discount. The Commission invites the Company and intervenors to explore this issue further in the Company's next rate case.

5. Peak-Controlled Tiered & Peak-Controlled Tiered TOD Tariffs

The Company proposed to close the present Peak-Controlled and Peak-Controlled TOD Service schedules to new customers. NSP has designed two new rate schedules which incorporate some of the provisions from the existing schedules and address some of the concerns of large industrial customers for increased options.

The major change in the new schedules is the separation of the interruptible class into two interruption priority groups called Tier 1 and Tier 2. The terms and conditions of service associated with the two priority groups determine the customer's qualification for different levels of demand charge credits. Under the assumption of a constant controllable load, the average monthly demand charge credit for a Tier 2 customer is: $3.06 per kW for a performance factor less than 65 percent; $3.40 per kW for a performance factor between 66 and 85 percent; and $3.80 per kW for a performance factor greater than 85 percent. Tier 1 customers with a performance factor less than 85 percent receive a demand charge credit of $4.00 per kW, and for a customer with a performance factor greater than 85 percent the demand charge credit is $4.50.

The Company indicated that the demand charge credits proposed for these rate schedules are within the range of appropriate discount levels it had developed in its Interruptible Rates Study ordered by the Commission, and included in its rate case filing.

The major difference between Tier 1 and Tier 2 provisions is the maximum hours of interruption and the frequency of control periods. The Tier 1 rate includes a higher demand charge credit than the Tier 2 rate with more hours of possible interruption and a longer contract term. Overall, the Tier 1 service is significantly more restrictive than Tier 2. Tier 1 customers would be required to commit to a ten year contract with a five year cancellation notice, while Tier 2 customers would be subject to a five year contract with a six month cancellation notice. Also, Tier 1 has a maximum of 150 hours of interruption per year while Tier 2 customers will be subject to a maximum of 80 hours of interruption per year. Tier 2 customers would be divided into two subgroups with alternating control period days. Tier 1 customers would not be divided into subgroups with alternating control period days. Tier 1 customers would be subject to a control period to match the needs of NSP's system. Tier 2 customers would remain subject to the normal control period guideline of 12:45 PM to 6:15 PM.

The Department did not oppose the Tiered system of interruptible rate options nor the division of Tier 2 customers into subgroups with alternating days of interruption. Also, the Department did not oppose the demand charges proposed by the Company, but argued against the Company's method of calculating the floor, or lower limit, used to develop the demand charges. The Department argued that the floor should be based on the cost of providing service to a class of customers rather than reducing the firm rate by an adjusted cost of a combustion turbine.

The Department's main concern with the Peak-Controlled Tiered tariffs is the level of the demand charge discounts. The Department asserted that the proposed rate discounts are not derived from any testimony in this proceeding and no theoretical support is clearly identified. The Department recommended that the Company study the possibility of offering a menu of interruptible rates with different terms and conditions with corresponding demand charge discounts. The Department argued that the Company should implement the results of the study in its next general rate case.

The ALJ found the proposed tiered system of interruptible rates to be based on substantial evidence in the record, in the public interest, and appropriate for adoption.

In its Order in the Company's last rate case, the Commission specifically identified interruptible rates as an issue that it considered important and directed the Company and interested parties to address a wide range of interruptible rates options. The Company took the directive of the Commission seriously and studied its own interruptible rates and those offered by other utilities. The Company also held extensive meetings with its interruptible customers. One of the results of these efforts is the Company's proposed Peak-Controlled Tiered Service schedules.

The Commission finds the proposed Peak-Controlled Tiered and Peak-Controlled Tiered TOD Service schedules to be an improvement over the existing Peak-Controlled and Peak-Controlled TOD Service schedules. The efforts of the Company to address the concerns of the Commission and intervenors on the appropriate level of rates, discounts, and options for interruptible service are exemplified in the Company's proposal of the Tiered system.

The Commission finds that there is support for the proposed demand charge discounts in the record. The proposed levels are within the range of appropriate discounts developed by the Company in its Interruptible Rates Study. Indeed, the discounts proposed by the Company are within the range of appropriate demand charge discounts developed by the Department. The question becomes what is the optimum level of discount and how is it to be determined.

The actual level of the demand charge discounts chosen by the Company is the result of cost information and negotiation with its C&I customers. At this time, the Commission believes this approach is appropriate. The Commission believes that the Company will need to examine the results of the new rate schedules, including its customers' responses to the new terms and rates of the Tiered system. While the Commission remains optimistic, it does not believe that this issue can be resolved in one rate proceeding. Interruptible rate levels, service options, and contract terms will likely need to be modified several times before a final solution is found. The increasing competitiveness of the electric industry may require that these rates be examined and re-examined by parties and the Commission on a regular basis. The Commission believes the interruptible rate proposals of the Company in this proceeding are a strong beginning and finds them appropriate for adoption, when adjusted for the lower revenue requirement.

6. Mandatory TOD Rates for Large General Service Customers

The Department recommended mandatory TOD rates for the largest C&I customers. The Department asserted that voluntary TOD rates have minimal effect on a utility's load pattern and cost of providing service. The Department argued that mandatory TOD rates are a critical tool for encouraging efficient energy use and therefore are a valuable instrument for resource planning. The billing impacts of the Department's proposal will vary depending upon how much load a customer shifts to off-peak periods.

The Department argued that charging customers more during peak periods encourages customers to shift loads to less expensive off-peak periods, improving NSP's load factor. Lowering peak demand means less investment in peaking capacity, reducing NSP's system costs per kWh and benefiting all customers on the system. If customers do not change their consumption patterns, TOD rates better reflect NSP's cost of providing service.

The Department recommended a two step process for implementing mandatory TOD rates. During the first step of the implementation process, NSP would provide customers with assistance to determine what changes in operations can be made to take advantage of lower off-peak rates. According to the Department, the actual implementation of the mandatory rates is the second step of the process.

The Department recommended that the Company continue to offer TOD rates on a voluntary basis for nine months or until the beginning of the 1994 summer period. At that time, NSP would require customers with loads of 500 kW or larger to take service under TOD rates. The 500 kW load level was chosen by the Department because it is a level which would allow the Company to gain experience with the rates for its largest customers and because the ratio of TOD metering costs to total bills is lowest for these customers.

Finally, the Department recommended that NSP be required to submit a plan detailing how it will implement mandatory TOD rates, including plans to contact customers to evaluate methods of decreasing peak consumption and to answer customer questions.

NSP argued it was unreasonable and unacceptable to require customers to transfer to TOD rates. Placing more customers on TOD rates is an appropriate long-term goal. The Company suggested that if the Commission believes mandatory TOD rates are appropriate, the Company should be allowed an opportunity to gain experience with its experimental three period TOD rates before the implementation of mandatory rates is ordered.

The Metalcasters of Minnesota opposed the implementation of mandatory TOD rates, arguing that the Department's proposal is inconsistent with the cautious approach the Commission has taken with TOD rates in the past. The Metalcasters asserted that the implementation of mandatory TOD rates would be unfair because it singles out customers who are unable to take advantage of load management rate discounts or who lack the economic flexibility to shift more of their load to off-peak periods. The Metalcasters argued that mandatory rates are not justified by any compelling legal or policy objective.

The ALJ agreed with the Company and indicated that if mandatory rates for large customers are an objective of the Commission, the Commission should allow the Company the opportunity to gain experience with the experimental three-period TOD rate schedules recently authorized. The ALJ asserted that experience with the three-period TOD rates will allow the Company to refine its rate schedules and allow for a smoother transition to mandatory rates.

The Commission finds that it is inappropriate to adopt the Department's proposal for mandatory TOD rates for NSP's largest customers at this time. The Commission agrees with the ALJ that the Company should be allowed the opportunity to gain experience with the recently authorized experimental three-period TOD rate schedules.

While TOD rates may better reflect the cost of providing service and may reduce peak demand and hence the need for peaking capacity, the Commission is concerned that mandatory TOD rates could have serious negative effects on existing companies who cannot shift load due to the nature of their business. The Commission is also concerned that the administrative and materials cost of implementing this proposal would be excessive. The Commission finds that NSP's General TOD rate proposals should be adopted, with rate levels adjusted for the lower revenue requirement.

7. Peak-Controlled & Peak Controlled Time of Day Service

The Company proposed to close the existing Peak-Controlled and Peak-Controlled TOD Service tariffs to new customers. These tariffs will be replaced by the new Peak-Controlled Tiered tariff and Peak-Controlled Tiered TOD tariff discussed previously in this Order.

The Company proposed to increase the energy charge for Peak-Controlled Service from 2.89 cents to 3.14 cents per kWh. The demand charge for firm demand was increased by approximately 12 percent for June through September and approximately 10 percent for October to May. The demand charge for controllable demand was increased approximately 20 percent year-round for Option A and 19 percent for Option B.

The voltage discounts per kW were increased approximately 27 percent for primary voltage, 17 percent for transmission transformed voltage and 17.5 percent for transmission voltage. The voltage discounts per kWh were reduced by 17 percent, 20 percent and 8.3 percent, respectively.

The Company also proposed to maintain the present level of the demand charge discount for both Options A and B.

For Peak-Controlled TOD Service, the demand charges for both seasons were increased by approximately the same amount as the Peak-Controlled Service. The charge for off-peak period demand in excess of on-peak demand was increased from $2.00 to $2.35 per kW. On-peak energy charges were increased from 3.33 cents to 4.67 cents per kWh, and off-peak energy charges were reduced from 2.5 cents to 1.97 cents per kWh.

The Company argued that its proposed modifications were made to encourage existing customers on these tariffs to move to the new tiered system it designed and proposed for adoption. None of the parties to the proceeding argued against the Company's proposals for these tariffs.

The ALJ found the Company's proposals for Peak-Controlled schedules to be reasonable and appropriate for adoption.

The Commission finds the Company's proposed modifications to the Peak-Controlled and Peak-Controlled TOD Service tariffs to be reasonable and appropriate for adoption when adjusted for the lower revenue requirement. In the last NSP rate case, the Commission ordered the Company to study various interruptible rates and options, in consultation with its customers, and present its findings in this rate case. The Company conducted the study as directed by the Commission and proposed the tiered system of interruptible rates. The Commission believes the tiered interruptible rate options are an improvement over the existing interruptible options. The Commission finds that it is reasonable to close the existing tariffs to new customers and to set the rates of these tariffs to encourage existing customers to change to the new interruptible options.

8. Experimental General Time of Day Service

On June 1, 1992, NSP filed its first proposal for a three-period TOD rate called the Experimental General TOD Service tariff in Docket No. E-002/M-92-457. On October 20, 1992, the Commission issued an Order approving the experimental tariff, with modifications. NSP proposed that the experiment be made available to a maximum of 30 customers. The Commission modified the Company's proposed tariff by requiring that at least 18 of the 30 participants come from the Municipal Pumping class. NSP was in the process of implementing this rate as of the filing of the rate case.

The Company has proposed modifications to the experimental rate to insure that it remains compatible with the Standard General TOD rate. The customer charge was set equal to that in the standard General TOD and the Summer on- and off-peak demand charges are the same as those proposed for the standard General TOD Service. The demand charge for the mid-peak period is at the same level as the proposed Winter on-peak demand charge of the standard General TOD Service. NSP revised its energy charges from a ratio of 2.30 to 1, to an updated ratio of 1.36 to 1.

The Department provided extensive testimony on the issue of time of day pricing. The essence of the Department's approach to determining appropriate time of day rates is to set them as closely as possible to marginal energy and capacity costs. However, in order to allow NSP to attain its Commission-approved revenue requirement, the Department suggested that the second best approach is to set the energy and demand charges so that their on-peak to off-peak ratios are similar to the corresponding ratios of the appropriate marginal costs. The Department argued that TOD rates should be set to promote the efficiency of NSP's system and not necessarily to maximize the number of customers taking service under TOD rates.

The Commission finds the Company's proposed modifications to be reasonable and the rate schedule appropriate for adoption when adjusted for the lower revenue requirement. The Commission recently reviewed the rates for this tariff when the Commission approved the experiment in October of 1992. Adjusting the rates of the experimental tariff to maintain its compatibility with the General TOD Service is appropriate. As indicated in other sections of this Order discussing rates for time of day tariffs, the Commission does not support strict marginal cost pricing for these rates based on the Company's 1989 marginal cost study. The Commission agrees with the ALJ that the data from that study is questionable for setting rates today.

9. Interruptible Load Control Option

The interruptible load control option allows NSP to directly curtail a customer's load. The Company proposes to delete from its Rules for Application the paragraph which references the Load

Control Option. No customers are on it and none have expressed an interest in being placed on it.

The Department initially opposed the closing of this option and recommended that NSP postpone closing it. In this rate case, NSP had also proposed to impose a penalty-per-failure to interrupt, under its proposed tiered system of interruptible rates. This policy will replace the present policy of a monthly penalty, which NSP contended provides little incentive for a customer to curtail load after already failing to control once during a given month. Given the Company's proposal for a penalty-per-failure to interrupt, the Department argued that customers may want to be placed on the Load Control Option in order to avoid incurring additional penalties. The Department later withdrew its opposition to closing the option, given the fact that no customers had indicated any interest in the option during any of the extensive meetings NSP had with its customers on interruptible service options.

The ALJ found the Company's proposal to be appropriate.

The Commission finds the Company's proposal to close the Load Control Option for its interruptible customers to be reasonable and appropriate for adoption.

10. Standby Service Rider Stipulation Agreement

On March 24, 1992, Arkla Inc. (Arkla) and the Minneapolis Energy Center, Inc. (the Energy Center) filed a joint complaint against Northern States Power Company regarding the Company's Standby Service Rider, Docket No. E-002/C-92-228. The Complaint alleged that NSP's application of the rider in periods of unscheduled maintenance or forced outage is not in accordance with the tariff. In such periods, NSP charges both the demand charge of the Standby Service Rider and the demand charge of the General Service schedule. Arkla further alleged that, if NSP's application is in accord with the tariff, then the tariff is unreasonable.

On April 9, 1992, the Commission met to consider Arkla's and the Energy Center's complaint. At the meeting the Commission concluded that substantive issues had been raised regarding the Company's Standby Service Tariff.

Arkla and the Energy Center later requested that the Commission accept the withdrawal of their complaint, without prejudice, so that they would be able to participate in any future proceeding regarding NSP's Standby Service Rider.

On April 28, 1992, the Commission accepted the withdrawal of the complaint. However, the Commission noted that underlying issues regarding NSP's standby service charges had been raised by the parties and remained unresolved. These issues include the utility's proper charge to customers for standing by with capacity and the proper relationship between General Service and Standby Service demand charges during customers' system outages. The

Commission directed that Standby Service rate issues be explored and developed in NSP's next general rate case.

a. Standby Service

The rates incorporated into the Stipulation Agreement in the instant docket are the same as those proposed by the Company in its initial filing. However, significant modifications were made to the application of those rates. Instead of charging both the Standby Service demand charge and the General Service demand charge during the customers' system outages, the Stipulation Agreement presented to the Commission provides for a grace period of 964 hours of unscheduled service at the Standby Service demand charge level. After the grace period, the customer will pay the General Service or General Service Time of Day demand charge instead of the Standby Service demand charge.

If the customer requires unscheduled standby service at times of NSP's system peak hours in which NSP has insufficient accredited capacity under the MAPP Agreement and the Company incurs additional capacity costs as a result of such unscheduled standby service, the customer shall pay peak demand charges in the month in which the unscheduled standby service occurs and for each of the five succeeding months. These peak demand charges shall be based upon the following:

a) If a customer notifies the Company at least three hours prior to NSP's system peak hour, such peak demand charges shall be based on one-sixth of any additional capacity costs incurred by the Company as a result of the unscheduled outage and will not include any MAPP after-the-fact capacity purchase costs incurred by the Company.

b) If the customer does not notify the Company at least three hours in advance of the Company's system peak hour, such peak demand charges shall be based on one-sixth of any additional capacity costs incurred by NSP as a result of the unscheduled outage.

The Agreement also requires the customer to file an annual projection of the scheduled maintenance on the facility to NSP. The length of the Required Notice for scheduled maintenance varies depending upon the estimated length of the outage.

b. Non-Firm Standby Service Option

NSP proposed an additional Standby Service option which was incorporated in the Stipulation Agreement. The proposed option is similar to the Scheduled Maintenance option in that the customer must schedule outages with the Company. The difference between the Scheduled Maintenance option and the Company's proposed Non-Firm option is that NSP is only required to make reasonable efforts to supply power when the customer requests it.

Under the Company's proposal, customers who take Non-Firm Standby Service would pay a lower monthly reservation fee which reflects only the distribution costs of providing service to them. The Non-Firm Standby Service customer assumes the risk that NSP may not be able to provide power when the customer requests it. A Non-Firm Standby Service customer would accept that there may be times when their load will be shut down if their primary energy supply is out of service and NSP is unable to provide Standby Service.

The ALJ found the Standby Service Agreement and Stipulation to be supported by substantial evidence in the record. The ALJ found that acceptance of it will result in just and reasonable rates. He noted that all parties had the opportunity to cross-examine witnesses and no opposition surfaced. All parties interested in the subject matter signed the agreement and the ALJ submitted it to the Commission under Minnesota Statute § 216B.16, subd. 1a.

The Commission finds the Standby Service Stipulation Agreement to be supported by substantial evidence in the record, in the public interest, and appropriate for adoption. The Commission finds that the parties to the Stipulation have made significant progress in developing more appropriate terms and conditions for standby service. The institution of an initial grace period before the customer is charged the General Service demand charges more appropriately recognizes the contribution Standby customers make to NSP's system by paying the monthly per kW reservation fee. At the same time, applying the demand charge after a certain number of hours and including provisions on peak periods address the Company's concerns about possible abuse of standby service. The non-firm option provides more flexibility and choices for NSP and its customers.

E. Other Rate Design Issues

1. Municipal Pumping and Small Municipal Pumping

NSP is proposing no changes in the basic design of these rates. The Company indicated that the Small Municipal Pumping rate was raised more than the overall increase to make it comparable to the corresponding Small General Service rate. The rates for the Municipal Pumping Service rate were raised to maintain its existing relationship to the General Service rate.

The Department agreed with the Company's proposals for these rates except that it recommended a smaller revenue responsibility for the Municipal Other class as discussed in the revenue apportionment section herein.

The ALJ found it appropriate to adopt the Company's proposed modifications to these rates and indicated his disagreement with the Department's recommendation to adjust the revenue responsibility of this class.

The Commission finds the Company's proposed modifications to be reasonable and appropriate for adoption. The Department's recommendation will not be implemented because the Commission adopted NSP's proposed CCOSS and revenue allocation.

2. Fire and Civil Defense Siren Service

NSP proposed to increase the rate for this service by the approximate amount of the overall percentage increase as filed by the Company.

The Department agreed with the Company's proposal, except for its recommendation to increase the revenue responsibility for this class as discussed in the Revenue Apportionment section of this Order. The ALJ recommended a lower overall increase to this rate according to his findings on the revenue requirement.

The Commission finds the proposed increase for Fire and Civil Defense Siren Service to be appropriate, when adjusted for the lower revenue requirement approved by the Commission.

3. Direct Current Service

The Company proposed to increase the energy charges the same amount as for Small General Service. The customer charge was increased from $6.60 to $7.00 and the demand charge per kW was increased from $2.50 to $2.75.

The Department agreed with the Company's proposal, except for its recommendation to increase the revenue responsibility for this class as discussed in the Revenue Apportionment section of this Order. The ALJ recommended a lower overall increase to this rate according to his findings on the revenue requirement.

The Commission finds the Company's proposed modifications to this rate to be reasonable, when adjusted for the lower revenue requirement.

4. Excess Energy-St. Anthony Falls Lock & Dam Tariff

The Company proposed to bring this rate in line with the corresponding standard General Service rate schedule. The demand charge in excess of the contracted demand is proposed to increase from $4.60 to $5.47 and the energy charge in excess of contracted energy is proposed to increase from 2.83 cents to 3.09 cents per kWh to keep it equal to the energy charge for primary voltage service on the General Service rate.

The Department did not oppose the Company's modifications. The ALJ found the Company's proposals to be appropriate and recommended approval.

The Commission agrees with the Department and the ALJ that the proposed increase for this rate schedule is appropriate, when adjusted for the lower revenue requirement.

5. Street Lighting Service and Automatic Protective Lighting Service

In NSP's last rate case the Commission deregulated the Company's maintenance service for customer-owned street lighting equipment. The Commission approved the Company's deregulation plan and accompanying tariff sheets on October 8, 1992. The Company incorporated these changes into this rate case filing.

In this rate case, the Company proposed to increase the overall revenue responsibility assigned to the Street and Area Lighting class by 1.8 percent. This increase was distributed among the various types of lighting services NSP offers. The proposed rates were determined in order to recover the class revenue responsibility and to reflect the relative cost differences associated with the components of service provided. Additionally, Rule No. 3, Outages, was revised to provide an outage credit based on the metered lighting rather than the total monthly rate.

The Department recommended that the Commission approve NSP's proposed modifications. The ALJ found the Company's proposals to be reasonable and recommended that they be adopted by the Commission.

The Commission agrees with the Department and the ALJ that the Company's proposed modifications to this rate are reasonable and appropriate for adoption, when adjusted for the lower revenue requirement. The Commission acknowledges that the Company has incorporated the changes ordered by the Commission in NSP's last rate case, and the subsequent miscellaneous docket, into this rate case.

6. Fuel Clause Rider

The Company proposed to change the base cost of fuel to match the test year fuel costs which have been reflected in the final base rates. NSP also sought comments regarding the appropriate level of sales to be used in the base calculation.

The Department recommended that the Company use calendar month sales to calculate the base cost of fuel in this proceeding, and that the Company discuss in its next rate case whether there is any significant overrecovery or underrecovery that requires a true-up mechanism.

The Company indicated its willingness to support the use of calendar month sales in the calculation of the base cost of fuel in order to be consistent with its new accounting method for unbilled sales and revenues. The Company will discuss the need for a true-up mechanism for significant over- or underrecoveries in its next rate case. The ALJ agreed with the Department's recommendation.

The Commission finds the Department's recommendation to use calendar month sales to determine the base cost of fuel to be appropriate. The calendar month calculation is consistent with the Company's new method of accounting for unbilled sales and revenues. The Commission also finds the proposal to discuss any significant over- or underrecoveries in NSP's next rate case to be reasonable.

7. Miscellaneous General Rules and Regulations

NSP proposed three revisions to its General Rules and Regulations. First, the Company proposed to revise the language in Section 5.1, Standard Installation, to no longer require customers to pay for operation and maintenance expenses associated with excess capital expenditures. During the Department's investigation into Minnesota electric utilities' service extension practices, Docket No. E-999/CI-90-1002, it became clear that NSP's method of charging future operation and maintenance expenses was not used by any other utility. Experience has shown that NSP's method causes controversy and confusion to customers and is difficult to administer. The Company is revising the language of this section to be consistent with other utilities in Minnesota.

Second, NSP proposed changes to the language in Section 5.4, Automatic Protective Lighting Service, to eliminate confusion as to when to charge a customer for Early Removal or Temporary Service charges. The Company asserted that the language should be changed to make a clear distinction between the use of a one-time payment method for facilities provided for service and the Early Removal or Temporary Service charges as stated in the tariff.

Third, NSP proposed clarifying language for Section 1.6, Refusal or Discontinuance of Service, in order to be consistent with the Disconnection of Service section of Minnesota Rules, Chapter 7820.

The Department did not object to any of NSP's proposed changes. The ALJ found the proposed revisions unopposed, reasonable and appropriate for adoption.

The Commission finds the revisions proposed by the Company for Section 5.1, Standard Installation; Section 5.4, Automatic Protective Lighting Service; and Section 1.6, Refusal or Discontinuance of Service to be appropriate for adoption.

8. Decoupling

At present, the Commission sets rates based on a utility's revenue requirements and sales levels. Under this method, utilities have an incentive to increase sales between rate cases in order to maximize profits. Those incentives may be inconsistent with least cost planning strategies which emphasize energy conservation and efficiency. Theoretically, decoupling removes the incentive to increase sales.

The Department recommended that the Commission initiate a generic investigation into decoupling methodologies for use in future rate case proceedings. The investigation would be patterned after the

Commission's investigation of financial incentives for demand-side management in Docket No. E-999/CI-89-212.

The ALJ found the Department's recommendation to be appropriate and recommended that the investigation be implemented. No other parties commented on the proposal.

The Commission has been investigating decoupling informally for approximately a year, in a number of forums. Among these have been a two-day in-house seminar last December, and discussions in the Chairman's Round Table seminars. At this time, the Commission does not feel it has completed the work it wants to accomplish informally, including evaluating this issue and its relative importance and urgency compared to other current regulatory issues.

After the Commission accomplishes this work, it will be in a better position to determine whether to undertake formal investigations. Therefore, the Commission will decline to initiate this formal investigation at this time.

9. New Marginal Cost Study

The Department proposed that the Commission order NSP to prepare a new marginal cost study for submittal in its next rate case. The Department relies heavily on marginal cost pricing, particularly for designing TOD rates.

The Company indicated its willingness to conduct a new marginal cost study if the Commission determined it to be appropriate. The ALJ found the Department's proposal to be appropriate.

The Commission will adopt the Department's proposal for a new marginal cost study to be prepared by the Company and submitted in its next rate case. To varying degrees, both the Company and the Department rely on the results of the Company's first and only marginal cost study in 1989 to set rates. The ALJ indicated that setting rates based on the 1989 marginal cost study was a questionable practice.

The Commission agrees with the Department and the ALJ that it is reasonable to order NSP to conduct a new marginal cost study and to submit the results in its next rate case. Marginal costs are important for setting rates and the Company has done only one such study four years ago. The Company, the Commission, as well as the Department and other intervenors, will benefit from a new marginal cost study.

10. Experimental Real Time Service

NSP was seeking comments on an Experimental Real Time Service Rider. The Company indicated that the Rider is an extension of the concept of the three period time of day rate approved by the Commission in October, 1992. The Rider, as envisioned by the Company, would have five price schedules for large C&I customers based upon five different day types on NSP's system. The tariff would send large customers better price signals by developing different price schedules for each of the different day types. The Company would estimate the cost characteristics of the upcoming day, determine which day type it was, and notify customers of the price schedule applicable on that day.

The Company indicated that it had several discussions with customers and received mixed reactions. Generally, the concept of the Real Time Service Rider was well received; however, the specifics of how NSP would determine the varying energy costs of the rider have not stimulated great interest. Therefore, NSP sought further input and direction from parties as to both the desirability and form of a Real Time Service Rider.

The Department recommended that the Company determine that there is sufficient customer interest before proceeding with the development of the rider.

The ALJ indicated his agreement with the recommendation of the Department that the Company determine whether there is sufficient customer interest before further development of an Experimental Real Time Service Rider.

The Commission agrees that rates which better reflect actual costs send more accurate price signals. However, the Commission, as well as other parties, is unable to comment on what the appropriate rates should be for the five different day types until the Company proposes an actual rider. The Company will need to convince the Commission that the cost differences between the five day types is significant enough to warrant the development of the rider and that it can attract customers to it.

The Commission finds that the Company should determine whether there is sufficient customer interest in such a rider before proceeding with its development.

ORDER

1. Northern States Power Company's Electric Utility is entitled to increase gross Minnesota jurisdictional revenues by $54,251,000 to produce gross jurisdictional Total Operating Revenues of $1,576,746,000 for annual periods beginning January 1, 1993.

2. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein.

3. The compliance filing filed pursuant to Ordering Paragraph 2 shall contain:

    a. a breakdown of Total Operating Revenues by type;

    b. schedules showing billing determinants and revenues by billing class for the retail sales of electricity;

    c. revised tariff sheets incorporating the rate design decisions contained in this Order; and

    d. proposed customer notices explaining the final rates.

4. Within 30 days of the date of this Order, the Company shall file with the Commission and the Department of Public Service (the Department) and serve on the parties a revised base cost of fuel and supporting schedules incorporating the changes made herein. The Company shall also file a fuel clause adjustment to be in effect at the time final rates become effective. The Department shall review these filings in the same manner as any other automatic adjustment filings.

5. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposal to make refunds, including interest calculated at the average prime rate, to affected customers. The proposal shall reflect the difference between the revenue collected during the interim rate period and the amount authorized herein, taking into account the refund adjustments authorized by this Order. The Company shall also address the matter of potential double recovery as discussed in the FAS 106 section of this Order.

6. Within 60 days after all administrative review of this Order has been exhausted, the Company shall file a report of its actual rate case expenditures in this docket.

7. Within 120 days of the date of this Order, the Company shall submit the results of a study of its nuclear cost estimation process, as described in the text of this Order.

8. Within six months of the date of this Order, the Department shall prepare a critique or analysis of Company's current purchasing procedures based on the documents already provided by the Company and present recommendations whether any further investigation is necessary.

9. Parties shall have 15 days to comment on the filings required in Ordering Paragraphs 1 through 8.

10. In its next general rate case filing, the Company shall be exempted from including the following items: comparisons of budgets to DRI guidelines; the budget documentation contained in Volumes 5, 6 and 7 of the current filing; translation reports linking cost element, cost activity, and project budgeting mechanisms on a common and consistent basis to assure an audit trail; and month-by-month and year-end summary reports of contingency fund transactions and project substitutions. Separately but contemporaneously with its next general rate case filing, however, the Company shall file this information with the Commission, serve copies on the Department and the RUD-OAG and make this information available for review by other parties upon their request.

11. In its next general rate case filing, the Company shall submit the results of a new marginal cost study.

12. In its next general rate case filing, the Company shall discuss any overrecovery or underrecovery resulting from the change to use calendar month sales in the calculation of the base cost of fuel.

13. In its next general rate case filing, the Company shall include its external funding mechanism for its FAS obligation, as described in the text of this Order.

14. In future matters involving disputed tax issues related to regulated utility operations, the Company will be required to petition the Commission at the time the final decisions are received on the disputed items requesting deferred accounting status for both tax credits and debits.

15. The Company shall report any changes in the contracts and fuel supply agreements between its regulated operations and the non-regulated refuse derived fuel operations.

16. The Company shall deposit the amounts collected in rates for decommissioning resulting from this proceeding in the proper funds and not permit any excess funds 1) to be applied to other costs or 2) to flow to retained earnings.

17. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Susan Mackenzie
Acting Executive Secretary

(S E A L)